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ECONOMIC AND ENVIRONMENTAL COSTS
OF ELECTRICITY AND NATURAL GAS
IN B.C. LOWER MAINLAND
SPACE AND WATER HEATING APPLICATIONS

Prepared for

MINISTRY OF ENERGY, MINES AND PETROLEUM RESOURCES

by

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This report is intended to provide information and analysis on the issues surrounding fuel choice with regard to economic and environmental costs.

The conclusions and recommendations reflect the author's views only and do not necessarily reflect those of the Ministry of Energy, Mines and Petroleum Resources.

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EXECUTIVE SUMMARY

- The purpose of this report is to develop estimates of the marginal economic and environmental costs of natural gas and electricity in B.C. Lower Mainland water and space heating applications. The estimated gas and electricity costs are compared and the present value savings using gas in both the water and space heating applications are identified. Differences between private and social cost perspectives are also identified and discussed.

- The marginal "economic" costs of gas and electricity for space and water heating depend on the incremental sources of supply; incremental transmission and distribution costs and losses; and end use requirements and efficiency factors. The marginal environmental costs depend on the nature and magnitude of the environmental impacts in production, transmission and end use.

- For natural gas, incremental requirements are likely to be met primarily from B.C. sources of supply in the short to medium term. The cost of this supply is not forecast to increase in real terms. Historical trends do not support the assumption of rising replacement costs and prices. Also, the emergence of new export opportunities for B.C. gas is not likely to raise its value or opportunity cost, because of the high cost of accessing these markets.

- In this study, the wellhead value of gas is forecast to remain at approximately $1.40 per GJ for the foreseeable future. This plus processing, transmission and distribution costs and losses is estimated to result in a marginal supply cost of approximately $2.90/input GJ for Lower Mainland water heating loads and $5.20/input GJ for space heating loads. The marked difference between water and space heating costs is due to their very different load factors. Water heating is estimated at 77%, compared to only 30% for space heating. This results in much lower transmission and distribution costs for water heating per delivered GJ.

- In addition to these "economic" costs, there are environmental costs associated with the production, processing, transmission and use of natural gas. In particular, there are significant air emissions associated with each stage of natural gas supply and use. The cost of these emissions are estimated on the basis of emission rates in processing through utilization, and damage or abatement cost estimates for each major pollutant. The "base case" results indicate marginal air emissions environmental costs of approximately $1.55/GJ.

- Adding the environmental and "economic" cost estimates indicates a total marginal gas cost of some $4.45/input GJ for water heating and $6.75/input GJ for space heating. The total cost per output GJ (taking appliance efficiency factors into account) is estimated at approximately $8.10/GJ for water and $7.50 to $10.40/GJ for space, depending on furnace type.

- For electricity, in the short to medium term incremental requirements will be met by diversions from exports, Burrard thermal production and imports. Over the longer term they will be met by new hydro projects and IPPs.

- B.C. Hydro studies indicate that the marginal cost of electric energy is relatively low in the short term, but will significantly increase over the next ten to twenty years. Including generation, transmission and distribution capacity costs and losses, the marginal cost of electricity is estimated to increase from some 2.8¢ to 5.8¢ per input kwh for water heating loads and 4.4¢ to 7.9¢ for space heating loads over the next twenty years. Again, the difference in the costs for the two types of loads is due to their different load factors.

- As with natural gas, there are significant environmental costs associated with electricity supply. In the short to medium term, the principal impacts (associated with an increase or decrease in electricity use) are on thermal production in B.C. and elsewhere, giving rise to significant air emission effects. The cost of these emissions, taking into account greenhouse gas emissions in all jurisdictions as well as the emissions of all major pollutants in B.C., is estimated at .8¢/kwh. This is based on emission rates in all of the thermal plants affected by a change in B.C. demand plus estimates of damage and abatement costs for each major pollutant

- Combining the air emissions environmental costs with the estimated marginal cost of generation, transmission and distribution results in a total electricity cost of 3.6¢ rising to 6.6¢ per input kwh for water heating loads and 5.2¢ rising to 8.7¢ for space heating loads. Based on an estimated 82% efficiency factor for electric water heating, the total cost per output kwh would be 4.4¢/output kwh rising to approximately 8¢/output kwh. The cost per output kwh for space heating is the same as the input kwh cost because of an assumed 100% efficiency factor.

- Based on the cost estimates as summarized above, it is concluded that the estimated marginal economic and environmental cost of natural gas is less than electricity for both water and space heating applications, on an input and output (i.e. appliance efficiency factor adjusted) GJ basis. The difference is due to the basic economic or supply cost; the estimated marginal environmental (air emission) costs for the two fuel sources are quite similar.

- The present value savings using gas favour the use of gas in new or required replacement appliance investments. However, the results suggest that it is not clear they would justify the conversion from electricity to gas in water heating applications. The present value social cost savings would not be sufficient to offset the cost of a new gas heater. Space heating conversions could be economic, unless constrained by the specific characteristics of the dwelling.

- The present value savings using gas and, consequently, the attractiveness of using or converting to gas will differ from a social cost and private perspective. Social costs are different from the marginal prices for gas and electricity. Also, the discount rate individuals apply can be considerably higher than a social discount rate based on the social opportunity cost of capital. The differences between estimated social costs and prices for gas and electricity tend to overstate the social cost savings using gas for water heating and understate them for space heating. The high private discount rate reduces the perceived present value savings in both applications. As a result the decisions individuals make can be different from what would appear most efficient from a social perspective.

1.0 INTRODUCTION

In a previous report for MEMPR, see supplement, Marvin Shaffer and Associates Ltd. outlined the components of the economic and environmental costs of different energy sources used in space and water heating applications.[1] The report also indicated reasons why costs from a social or overall provincial perspective could differ from the market prices that consumers face and that influence their fuel choices.

Cost components were grouped into production, transmission and distribution, and end use. Production costs were noted to be dependent upon incremental sources of supply; transmission and distribution costs on incremental capacity requirements and fuel and losses; and end use costs on equipment requirements and efficiency. It was also noted that the magnitude of these costs, measured from a social perspective, could differ from prices because of the regulation of electricity prices; potential differences between gas prices and social opportunity costs; and environmental impacts not reflected or incorporated into fuel prices.

No attempt was made in the previous MSA report to estimate the magnitude of the fuel costs or differences between social costs and market prices. That is the purpose of this report. Specifically, the terms of reference for this study call for **an estimation and comparison of the marginal economic and environmental costs of gas and electricity in B.C. Lower Mainland space and water heating applications.** The terms of reference also call for an identification of any differences between the estimated marginal costs and prices. A specific objective of the study is to estimate the benefits of substituting gas for electricity in Lower Mainland space and water heating applications. The estimated marginal economic and environmental costs are used to estimate benefits from a social perspective; actual prices are used to indicate the perceived benefits from a private perspective.

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[1] **Marvin Shaffer & Associates Ltd., Fuel Choice in Space and Water Heating Applications in British Columbia, prepared for MEMPR, December, 1990.**

B.C. Hydro was the principal source of information on electricity costs. Resource planning staff at B.C. Hydro provided results from three runs of their Resource Planning Model, including a base case and two alternative cases with reduced loads. These runs indicates the effects that a change in the load has on Hydro's current Resource Plan in terms of sources of new supply and their in-service dates, imports and exports, and marginal energy costs. Other B.C. Hydro material contained information on marginal capacity costs. Applications to the National Energy Board by Westcoast Energy were key sources of information on natural gas supply, demand and costs in the province.

Information on environmental impacts of electricity and natural gas was collected from a variety of sources. A previous report by Marvin Shaffer & Associates provided information on air emissions associated with incremental changes in electricity demand.[1] Information from Environment Canada, Statistics Canada, Department of Energy, Mines and Resources and Westcoast Energy was used to estimate air emissions from natural gas processing, transmission and end use.

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[1] Marvin Shaffer & Associates Ltd., **Environmental Benefits of Demand Side Management in British Columbia,** prepared for B.C. Hydro, January, 1991.

2.0 INCREMENTAL SOURCES OF SUPPLY

2.1 Natural Gas

Except for the relatively small amount of natural gas imported from Alberta into southeastern B.C. off the Alberta Natural Gas pipeline,[1] B.C. domestic gas requirements are supplied via the Westcoast Energy transmission system. Westcoast collects gas in northeastern B.C., Alberta and the Northwest Territories for processing and delivery to B.C. and export markets. The bulk of the gas is produced in northeastern B.C., accounting for over 90% of Westcoast's total supply.[2]

Gas deliveries through the Westcoast system totalled $11{,}376 \times 10^6 m^3$ in 1990, of which some 60% was for the domestic market and 40% for export. Westcoast is forecasting total deliveries to increase to some $18{,}955 \times 10^6 m^3$ by the year 2001, representing an average annual growth rate of 4.75% over the 1990-2001 period. This high growth rate is due in large part to new pipeline connections opening up new markets in Vancouver Island and California, and anticipated new gas demand for electric generation in B.C. and the United States. Growth in the traditional market areas and sectors is expected to be relatively modest, increasing at some 2%/year.[3]

Westcoast is currently expanding its facilities to meet growing gas requirements. Over the past year it has applied to the NEB for approval to expand its McMahon processing plant, its Fort Nelson mainline capacity and its southern mainline capacity. Total delivery capacity after the southern mainline expansion will be 45,976 x 10^3m^3/d (1623 MMcf/d). Further expansions will be required if demand grows as Westcoast is forecasting.

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[1] Imports into southeastern B.C. totalled some $480 \times 10^6 m^3$ in 1989 and $380 \times 10^6 m^3$ to the end of October in 1990 (B.C. MEMPR, **Oil and Gas Production Reports**).

[2] In 1989, B.C. production accounted for 94.2% of the total supply entering Westcoast's system (B.C. MEMPR, **Oil and Gas Production Reports**).

[3] Westcoast Energy, **Application to the NEB for Expansion of the Southern Mainline Looping**, March, 1991.

With respect to sources of gas, Westcoast's deliverability forecasts indicate that supply from proved remaining reserves and trend gas would be sufficient to meet the growth it anticipates through the end of 2001. Deliverability through the Fort Nelson and Fort St. John mainlines could be maintained at some 52,000 x 10^3m^3/day over the 1992-2001 period. Deliverability through the Pine River mainline could increase from 3400 to 8500 x 10^3m^3/day.[1] Thus, for the foreseeable future incremental gas requirements can be expected to be met primarily from B.C. sources. The mix of incremental sources within B.C. is unclear, though increases through the Fort Nelson and Pine River plants would be expected to dominate given current patterns of exploration activity.

2.2 Electricity

B.C. Hydro sold over 48,500 Gwh of electricity in 1990-91, 94% of which was for the domestic market. Almost 47,000 Gwh was supplied from the utility's hydro-electric facilities, with the balance coming from its Burrard gas-fired thermal plant, purchases from Alcan and imports from Alberta and the United States.[2]

B.C. Hydro is forecasting that domestic requirements will grow by 2.2%/year over the 1991-2000 period and 1.7%/year over the 2000-2010 period. However, not all of this will have to be met by new supply. In its 1991 Resource Plan, B.C. Hydro expects reductions in the amount of power it will have to provide from new or existing sources of supply because of the repatriation of the downstream benefits under the repatriation of the downstream benefits under the Columbia River treaty,[1] demand side management, self-generation by industry and Resource Smart initiatives.[2] Thus, the net domestic load it will have to supply is forecast to grow by only 0.5%/year over the 1991-2000 period and 1.6%/year over the 2000-2010 period.

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[1] Ibid.

[2] Sales and production estimates from B.C. Hydro 1990-91 Planning model.

To meet the growth in the net domestic load, B.C. Hydro's current Resource Plan calls for the purchase of 1700 Gwh/year of privately-produced power (IPPs) starting in 1994, purchases of 2500 Gwh/year from Alcan starting in 1995, construction of new generating capacity at the Seven Mile, Waneta and Brilliant dams between 2005 and 2008, additional IPP purchases beginning in 2007 and extensive use of the Burrard thermal plant.

B.C. Hydro's current Resource Plan is significantly different from previous resource plans. Net domestic requirements had previously been forecast to grow more rapidly and large hydro projects were to be relied upon more extensively to meet future requirements. For example, in the 1990 Resource Plan, the net domestic load was forecast to grow at an annual rate of 1.1% over the 1990-1999 period and 1.7% over the 2000-2009 period. Less DSM and less self-generation was assumed. Also, the 1990 plan called for much greater reliance on new hydroelectric supply, with the Site C, Lower Canyon, Homathko and Elaho hydroelectric projects scheduled to be brought in-service over the 2002-2010 period. By way of comparison, the current plan relies much more on IPPs and added capacity at existing hydro sites.

The IPPs in the current plan include a range of generating technologies. The power to be purchased starting in 1994 will come from natural gas cogeneration, wood waste and small hydro. It is not known what the later IPPs will be, but one can expect they will include the same wide mix of sources.

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[1] This power source belongs to the B.C. government and it is not yet clear how it will be used. For planning purposes, B.C. Hydro is currently assuming it will be used to meet B.C. requirements.

[2] Downstream benefits are expected to provide 500 Gwh in 1998, 2800 Gwh/year from 1999-2002, 4800 Gwh/year from 2003 to 2006, and 4600 Gwh/year from 2007-2010. DSM is expected to reduce requirements by 4.5% of the gross domestic load in 1995 and up to 8.3% of the gross domestic load in 2010. Self generation is expected to reduce B.C. Hydro requirements by 3500 Gwh/year after 1997. Resource Smart is expected to reduce new supply requirements by 200-300 Gwh/year.

In order to identify incremental sources of electricity, B.C. Hydro planning staff analyzed how changes in the load would affect production and sales levels and the timing of new purchases or additions to capacity. Two cases were considered in addition to their base case: one with a 5% reduction in the domestic load; the other with a 7.5% reduction in the domestic load.[1]

In Table 1, the estimated production and sale impacts of the assumed reductions in load are summarized for four selected years. In the short to medium term, the principal impacts would be on interruptible exports sales and Burrard thermal production. They are, in effect, the major short to medium term marginal sources of supply -- the sources affected by a decrease (or increase) in the domestic load given the current configuration and capacity of the Hydro system.[2]

Over the long term (after 2004), the principal impacts would be on IPP purchases and hydro production. These are the major long run marginal sources of supply -- the new sources of supply that can be reduced or delayed due to a decrease in the load (or increased and advanced if there was an increase in the load).[1]

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[1] These cases identify the "decremental" as opposed to "incremental" sources of supply, i.e., the avoided sources due to a decrease in demand as opposed to the new sources associated with an increase in demand. It can be assumed that the decremental and incremental sources are the same. Reductions in the load were analyzed for the later consideration of the substitution of gas for electricity. Residential electric water heating accounts for approximately 5.2% of B.C. Hydro's load and the first case reflects the maximum impact of water heating conversions to gas. Residential water and space heating account for 7.5% of Hydro's load and the second case indicates the maximum impact of water and space heating conversions. (Load Research Analyst, B.C. Hydro)

[2] While one does not normally consider a market destination as a source of supply, interruptible exports are a swing market, which can be increased or reduced in accordance with changing domestic requirements. It is in that sense that it is a marginal source of supply for the domestic market.

TABLE 1

Impacts of Reduced Load on B.C. Hydro Resource Plan

(Gwh)

5% Reduction in Load	1994-95	1999-2000	2004-2005	2009-2010
Change in Domestic Load	(2620)	(2900)	(3325)	(3678)
Change in Hydro Production	(194)	(554)	(263)	(381)
Burrard Thermal Production	(694)	(654)	(671)	(13)
IPP Purchases	0	0	0	(3000)
Other Production	(334)	(191)	(525)	(78)
Change in U.S. Export Sales	1171	1171	1412	105
Other Inter. Sales	228	326	254	5
7.5% Reduction in Load				
Change in Domestic Load	(3942)	(4383)	(4962)	(5500)
Change in Hydro Production	(365)	(979)	(490)	(1298)
Burrard Thermal Production	(1050)	(996)	(1011)	44
IPP Purchases	0	0	0	(4500)
Other Production	(436)	(262)	(716)	28
Change in U.S. Export Sales	1713	1631	2105	(198)
Other Inter. Sales	378	511	413	(74)

Source: B.C. Hydro Planning Staff.

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[1] With a 5% reduction in the load, B.C. Hydro planning staff indicated that the additions to hydro capacity would be delayed two years and IPP purchases would be delayed one year. With a 7.5% reduction in the load the addition to hydro capacity would be delayed four years and IPP purchases delayed two years.

The marginal sources of supply are markedly different in the short and long term. That is because the options are so different. In the short term a change in the load can only be met by diversions to (or from) other markets and reductions (or increases) in production from existing capacity like thermal plants which do not always run at full capacity. Over the long term, the expansion and purchase plan can change in accordance with the new requirements.

3.0 ECONOMIC AND ENVIRONMENTAL COSTS OF NATURAL GAS[1]

An increase in the use of natural gas for space and water heating would entail incremental gas production, processing, transmission and distribution for the domestic market and incremental end use equipment and losses. The economic and environmental costs associated with the incremental gas supply requirements and losses are discussed below.[2]

3.1 Gas Production Costs

As discussed in the previous section, increased gas requirements for the B.C. market would, for the foreseeable future, be met primarily by increased gas production in northeastern B.C. In the short term, the incremental requirements would be met by increased production from developed fields; over the longer term the incremental requirements could be met in part from new discoveries.

The cost of incremental gas supply (at the wellhead) is not just equal to the expenditures incurred to produce the gas and, over the long term, to find and develop it. Because dedicating gas to one market means that it is not available for other current or future uses, there is also a user or opportunity cost reflecting the net resource value of the gas over and above total expenditures to extract it.

Analysts have approached the measurement of this net resource value in a number of ways. For purposes of benefit-cost evaluations of gas export applications, National Energy Board staff recommended analyzing this net value in terms of the impact of current production on future supply costs. Their basic premise was that increased gas production depletes existing reserves and forces us to move to higher cost sources of supply. On the basis of estimates of the volumes of gas available at different cost levels and the expected rate of depletion, one can calculate the amount by which an increase in production (and therefore, an increase in the rate of depletion of existing sources of supply) will raise future costs. The present value of the increase in costs is defined as the user cost and it measures the foregone net value or opportunity cost of current production.

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[1] All values in this and the following sections are reported in constant 1990 dollars.

[2] End use equipment costs are addressed in section 5.

The National Energy Board abandoned this benefit-cost methodology, in part because of industry concerns about benefit-cost tests of export applications, but more fundamentally because of considerable uncertainty surrounding the reserve and cost estimates underlying the calculations, and consequently, considerable concern about the reliability of the benefit-cost results.

Indeed, there is uncertainty not simply with respect to the specific estimates of how much reserves are available at different cost levels, but also whether the basic premise of rising costs is valid. The NEB methodology assumes there is a fixed stock of gas reserves (even if undiscovered) which will be exploited in a predictable manner, moving from lower to higher cost sources of supply. In effect, it is assumed that the replacement cost of gas will rise with the depletion of higher quality, more accessible reserves. However, for reasons discussed in Appendix A, historical data do not support that basic premise. There is no apparent upward trend in natural gas replacement costs, nor is there reason to assume there will be one in the foreseeable future. While gas reserves are finite, technological improvements and unanticipated discoveries have offset the potential adverse cost effects of depleting existing reserves.

What this suggests is that the net resource value of natural gas depends not on the effects of depletion, but rather on the foregone sales or opportunities in alternative markets. In other words, the cost of incremental supply equals production costs, plus the net return that could have been realized in the best, alternative market. Since the foregone net return equals the alternative market price netted back to the wellhead minus production costs, this means that the wellhead cost of incremental supply for the domestic market simply equals the netted back price from the best possible alternative sale.

In Appendix B, alternative markets for B.C. gas are reviewed and it is concluded that while B.C. will be selling into a wide range of market areas, including California, Eastern Canada and possibly Northeastern U.S., the major alternative market for B.C. gas is and will remain the U.S. Northwest. This is the market where B.C. gas is most competitive relative to other gas sources and where the highest netbacks on long term firm sales are likely to be realized.

The U.S. Northwest market is among the most competitive markets for natural gas in North America. Table 2 shows 1990 prices of Canadian gas exported to the U.S. Northwest. The first two columns show spot prices at Huntingdon and the comparable netback spot price at the B.C. wellhead. The next three columns show the commodity prices of firm Canadian gas exported to the Northwest via Huntingdon. The commodity price is the price for the gas itself and as such is a price applicable at the wellhead.

As shown in the table, the spot prices have been very low, except in peak heating months. The price of firm gas has been higher, but the average 1990 netted back price was still only in the $1.35 to $1.44/GJ range.

TABLE 2

Prices of Canadian Gas Exported to the U.S. Northwest

(Cdn. $/GJ)

1990	Huntingdon Spot	B.C. Wellhead Spot	Amoco Wash. Nat. (Firm Commodity)	Westcoast NW Nat. Gas (Firm Commodity)	Can. West NW Nat. Gas (Firm Commodity)
January	2.17	1.51	1.53		
February	1.78	1.12	1.53		
March	1.34	0.68	1.52		
April	1.28	0.62	1.34		
May	1.21	0.55	1.34		
June	1.20	0.54	1.33	1.50	1.26
July	1.24	0.58	1.32	1.54	1.29
August	1.26	0.60	1.33	1.52	1.35
September	1.22	0.56	1.34	1.50	1.40
October	1.42	0.76	1.34	1.14	1.31
November	1.42	0.76	1.53	1.51	1.51
December	1.80	1.14	1.53	1.49	1.50
Wt. Ave. Prices		0.82	1.44	1.40	1.35

Source: The Huntingdon spot price series is from **Canadian Natural Gas Focus.** The B.C. spot wellhead price equals the Huntingdon spot price less Westcoast charges for transportation, processing and gathering. A 10% acid gas content is assumed. Westcoast's processing costs vary according to the sulphur content of the raw gas stream. The firm commodity prices are from the U.S. Department of Energy, **Natural Gas Imports and Exports,** quarterly reports (last available - 4th Quarter 1990).

Recent contracts negotiated for the sale of firm gas in the Northwest highlight the importance of spot and fuel oil prices in determining future price trends. For example, in firm sale contracts recently signed between Mobil Canada and three Northwest utilities, the commodity price of gas is weighted 25 percent on the B.C. residential gas price, 25 percent on the price of number 6 fuel oil in Seattle, 25 percent on the price of spot gas at Huntingdon and 25 percent on the spot price of U.S. Rocky Mountain gas. The relatively high weighting given to spot prices (gas and No. 6 fuel oil) indicate that LDCs in the Northwest are prepared to buy on the spot market if commodity prices of contract gas are uncompetitive. However, the 25 percent weighting given to the B.C. residential price indicates that the security of firm supply warrants some premium over spot prices.

With respect to future prices, there is general agreement that prices will not increase over the next one to two years, because of pipeline constraints to higher-valued markets in the U.S. However, with the new pipeline capacity scheduled for the U.S. northeast and California in 1992 and 1993, there could be a diversion of gas from the lower priced markets like the U.S. Northwest to these other areas. This could raise prices in the Northwest. Also, many industry analysts predict a gradual elimination of the "excess" supply in North America responsible for the gas-on-gas competition currently depressing gas prices.

It is not clear that the opening of new markets will significantly raise prices in the U.S. Northwest. The high cost of accessing the higher-valued markets will continue to constrain netted back prices at the wellhead. Also, it is certainly not clear that there will be a reduction in gas supply and gas-on-gas competition. Industry has been incorrectly predicting tighter supply and rising prices in the U.S. for a number of years. It has consistently underestimated the supply response of the conventional industry and may well be underestimating the potential for new sources such as coal seam gas. The presumption of rising prices is basically premised on the assumption of rising replacement costs due to the depletion of existing reserves. As discussed in Appendix A, there is little reason to believe that assumption is correct.

Thus, in our view there is little reason to expect markedly rising prices and opportunity costs for B.C. gas. While there is uncertainty over the exact direction of future prices, for purposes of this study the current wellhead value in the order of $1.40/GJ for firm supply is assumed to be maintained in real terms for the foreseeable future. An alternative scenario, with modestly rising prices, is considered in section 5.3, for sensitivity test purposes.

3.2 Gas Processing and Transmission Costs

The Westcoast system is operating at capacity, at peak periods, and is currently being expanded to meet growing requirements. Further increases in demand will require further additions to capacity.

Information on the costs of expanding processing and transmission capacity is provided in the recent facility application by Westcoast to the NEB. Table 3 presents the incremental volumes and expenditures associated with the McMahon and southern mainline expansions. Based on those capacity and expenditure figures, the incremental cost of processing is 48¢/Mcf and for transportation 27.5¢/Mcf, calculated on an average levelized basis at a 15% nominal discount rate.[1]

These incremental costs (particularly for processing) exceed Westcoast's current average costs of service, which are 22.9¢/Mcf for processing, 26.7¢/Mcf for transportation and 13.6¢/Mcf for gathering.[2] While it is not clear how future expansion costs will compare to current ones, one can expect they too will be above current costs of service, tending to pull up Westcoast tariffs over time.

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[1] Average levelized values are calculated by dividing the present value of expenditures by the present value of the incremental output. It measures the constant charge per unit of output which would generate annual revenues equivalent in present value to the total costs.

[2] Based on information from Westcoast. The transportation estimate is for delivery to Huntingdon. The processing estimate includes liquid recovery as well as treatment. It is based on a 10% acid gas content, the current Westcoast average.

TABLE 3

Incremental Processing and Transmission Expansion Costs

Year	McMahon Processing			Southern Mainlines		
	Capacity (mmcfd)	Capital ($'000)	O & M ($'000)	Capacity (mmcfd)	Capital ($'000)	O & M ($'000)
1991	14.26	85,970	210	14.19	52,520	42
1992	85.64		1309	85.00		265
1993	85.64		1362	85.00		278
1994	85.64		1416	85.00		294
1995	85.64		1473	85.00		312
1996	85.64		1532	85.00		331
1997	85.64		1593	85.00		351
1998	85.64		1657	85.00		372
1999	85.64		1723	85.00		394
2000	85.64		1792	85.00		418
2001	85.64		1864	85.00		443
2002	85.64		1939	85.00		470
2003	85.64		2016	85.00		498
2004	85.64		2097	85.00		528
2005	85.64		2181	85.00		559
2006	85.64		2268	85.00		593
2007	85.64		2358	85.00		628
2008	85.64		2453	85.00		666
2009	85.64		2551	85.00		706
2010	85.64		2653	85.00		748
2011	85.64		2759	85.00		793
1990 PV @ 10%		78,155	13,570			3158
1990 PV @ 15%		74,757	9148			2075
1990 PV @ 20%		71,642	6605			1467

Source: Westcoast Energy, Applications to NEB for Expansion of the McMahon Processing Plant, November, 1990, and Expansion of the Southern Mainline Looping, March, 1991.

Rising Westcoast tariffs will tend to increase the cost of delivering gas to the Lower Mainland for space and water heating purposes. At the same time, however, unless they affect the value of B.C. gas in its principal export markets, rising processing and transmission costs will reduce the wellhead value or supply cost of the gas. Thus to be consistent with the estimation of the wellhead value or cost in the previous section, processing and transmission costs are based on Westcoast's current costs of service.

Westcoast's current costs of service for processing and transmission total 49.6¢/Mcf or 47¢/GJ. In addition there is the 13.6¢/Mcf or 12.9¢/GJ charge for gathering which is applied to raw gas volumes. The total cost is 61¢/GJ of marketable gas.[1] This is the cost at a 100% load factor.

Water heating loads have a relatively high load factor; space heating load factors are relatively low. While specific estimates are not available for the Lower Mainland, studies in other areas suggest load factors of some 77% for water heating and 27% to 30% for space heating.[2] At a 77% load factor, the processing and transmission cost for a water heating load would average 79¢/GJ. At a 30% load factor, the cost for a space heating load would average $2.03/GJ.

The marked difference in the average and 100% load factor cost, particularly for space heating loads, indicates the potential benefits that storage facilities in the Lower Mainland could provide. For space heating, the benefits could exceed $1.40/GJ. However, recent storage proposals have met considerable opposition and it is not clear whether and at what cost gas storage could be developed in the lower Fraser Valley.

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[1] With a loss rate of 9.5%, the gathering cost is approximately 15¢/Mcf or 14.2¢/GJ of marketable gas.

[2] See Marbek, **Electricity Consumption and Acid Rain in Ontario**, prepared for Ontario Ministry of Energy, 1989 and P.Chernick, et. al., **Analysis of Residential Fuel Switching as an Electricity Conservation Option**, prepared for the Boston Gas Company, September, 1990. Both sources estimate load factors for electricity; they are used here as approximations for gas service load factors.

Thus, no reduction in delivery costs with the use of storage is assumed for the foreseeable future.

In addition to Westcoast gathering, processing and transmission charges, there are transmission fuel and losses for delivery to the Lower Mainland. These are estimated to average 2%, based on Westcoast gas receipt and delivery data compiled by MEMPR.[1]

3.3 Distribution Costs

The incremental distribution costs for expanding gas service to accommodate more users (e.g. an additional space heating load) or more intensive use (e.g. an additional water heating load by an existing gas user) depend on the impact that the additional load has on system requirements and design. In some circumstances, where the system design already provides for sufficient capacity to meet additional loads, the incremental distribution costs could be negligible. However, in general, over the longer term, one could expect additional loads would entail significant incremental costs due to their impacts on delivery and receipt capacity requirements.

Data are not available on incremental distribution costs for the B.C. Gas system. For purposes of this study an estimated average cost of residential gas service ($1.55/GJ at a residential average load factor of approximately 33%)[2] is used as a proxy for long run incremental cost. On the assumption that the costs of service are driven primarily by capacity requirements, this average cost can be converted to a 100%

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[1] This is an average for B.C. deliveries. They somewhat underestimate fuel and losses to the Lower Mainland because of the longer average distance compared to all Westcoast deliveries. Also, they will understate fuel and losses for space heating loads because of the higher fuel and loss rate at peak periods.

[2] Based on an estimate from industry sources.

load factor cost of approximately 51¢/GJ. On this basis, the costs for space heating loads would be $1.70 per delivered GJ, based on an estimated load factor of 30%; the costs of water heating loads would be 66¢ per delivered GJ, based on an estimated load factor of 77%.

In addition to the above costs there are distribution fuel and losses. These are estimated to average .2% of receipts.

3.4 Gas Supply Cost Summary

The incremental or marginal gas production, processing, transmission and distribution costs for space and water heating applications, as discussed above, are summarized in Table 4. The total costs per input GJ, taking fuel and losses into account, are estimated at approximately $2.90 for water heating applications and $5.20 for space heating applications. The higher costs for space heating reflect its much lower load factor and consequent higher transmission and distribution costs per delivered GJ.

TABLE 4

Gas Supply Cost Summary

	Water Heating *	Space Heating **
Production ($/marketable GJ)	1.40	1.40
Processing and Transmission ($/marketable GJ)	.79	2.03
Distribution ($/input GJ)	.66	1.70
TOTAL + ($/input GJ)	2.91	5.22

* Based on load factor of 77%
** Based on load factor of 30%
+ Including fuel and losses of .2% for distribution and 2% for transmission.

In Table 5, the total costs are adjusted to take appliance efficiencies into account. The estimated efficiency factors were provided by B.C. Hydro staff. For water heating, the gas appliance efficiency factor is estimated at 55%. This results in a total gas supply cost of approximately $5.30/output GJ. For space heating, the efficiency factors range between 65% and 90% depending on the type of furnace. The resulting total gas supply costs range from some $8.00/output GJ (for a conventional furnace) to $5.80/output GJ (for a high efficiency condensing furnace).

TABLE 5

Gas Supply Costs per Output GJ

	Water Heating	Space Heating
Supply cost per Input GJ	2.91	5.22
Appliance Efficiency	55%	65% (conventional) 80% (intermediate) 90% (condensing)
Supply Cost per Output GJ	5.29	8.03 (conventional) 6.53 (intermediate) 5.80 (condensing)

3.5 External Effects

The production, processing, transmission and utilization of natural gas give rise to a number of environmental impacts not reflected in the supply costs summarized above. These "externalities" or external effects[1] include land use, water and wildlife impacts associated with exploration activities and pipeline and facility developments, and air quality impacts associated with the processing, transmission and combustion of gas.

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[1] Externalities or external effects refer to adverse impacts or costs not borne by the suppliers or users of gas.

Land, water and wildlife impacts associated with incremental gas use are difficult to identify because they depend upon the specific location and manner of the exploration activity and plant or pipeline expansions undertaken to meet growing demand. In general, however, these impacts arise because of the alienation of land for drill sites, processing facilities, pipelines and waste disposal areas, as well as the potential pollution from waste disposal (e.g. scrubber slurry from processing plants). Wildlife impacts are mostly associated with pipelines, which can impede migration.[1]

No attempt is made to estimate the magnitude of any land, water and wildlife external costs due to incremental gas use.[2] However, the types and quantities of air emissions associated with incremental gas supply and use can be identified and measures of the costs they entail can be estimated.

For this analysis, emissions of the following air pollutants are examined: SO_2 (sulphur dioxide), NO_x (nitrogen oxides), CO_2 (carbon dioxide), particulates, CH_4 (methane), CO (carbon monoxide) and VOC's (volatile organic compounds). All of these are considered to be important pollutants from an environmental perspective. Sulphur dioxide is the major cause of acid rain. Nitrogen oxides produce acid rain, ground level ozone and contribute to the greenhouse effect. Carbon dioxide is the major greenhouse gas. Particulates reduce visibility, affect human health, and soil exterior surfaces. Methane is a greenhouse gas, roughly 76 times more potent than carbon dioxide. Carbon monoxide is a greenhouse gas and has adverse health effects. Volatile organic compounds contribute to ground level ozone which affects plants and human health and impairs visibility. Emissions of other pollutants (such as N_2O and heavy metals) also occur but these are not included in this analysis.

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[1] Chernick, Paul and Emily Caverhill, **The Valuation of Environmental Externalities from Energy Production, Delivery and Use**, December, 1989.

[2] To the extent that these or any other unknown external costs are significant, the social cost estimates reported here will underestimate the actual social costs of natural gas.

In Table 6, life cycle emissions rates for B.C natural gas are shown. The emissions include those associated with gas processing, transmission, distribution and end use. B.C. data on air emissions from gas production and gathering were not available.[1] Only the methane leakage is included; they are incorporated in the estimate of processing emissions.

TABLE 6

Life-Cycle Emission Rates for Natural Gas⁺

	SO_2	NO_x	CO_2	Part.	CH_4	CO	VOC	Weighting Factors for Fuel and Losses*
Processing (kg/000 m^3 marketable gas)	2.76	1.32	215.25	0.01	2.54	0.23	0.17	1.022
Transmission (kg/000 m^3 marketable gas)	0.00	0.04	44.78	0.00	0.06	0.01	0.00	1.022
Distribution (kg/000 m^3 citygate receipts)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.002
End Use (kg/000 m^3 household receipts)	0.00	1.63	1919.40	0.00	0.04	0.39	0.09	1.00
TOTAL								
kg/000 m^3 household receipts	2.82	3.02	2185.16	0.01	2.70	0.63	0.26	
kg/input GJ	0.07	0.08	56.58	0.00	0.07	0.02	0.01	

+ Excluding emissions associated with gas production and gathering.
* Based on 0.2% distribution and 2% transmission fuel and loss rates.

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[1] Significant air emissions do occur at this stage. SO_2 is produced when testing sour gas wells, and NO_x, CO_2 and other pollutants are emitted from compressors on the gathering system.

In the case of gas processing, air emissions occur primarily as a result of the stripping of contaminants (such as hydrogen sulphide and carbon dioxide), fuel combustion and methane leakage. Processing emission rates for all pollutants except CO_2 were based on a 1985 Environment Canada survey of common air pollutants[1] and Statistics Canada data on B.C. marketable gas production.[2] In the case of CO_2, emission rates were based on data provided by Westcoast. Methane leakage estimates for gas processing were based on a national survey by the Canadian Gas Association, reported by Environment Canada.[3] The processing emission rates reflect the current mix of gas supply sources. Emission rates from incremental sources may differ, but supply source-specific estimates were not available.

Emissions from gas transmission and distribution occur due to leakages in pipelines and fuel combustion in compressor stations. The leakage rates were based on the CGA study referred to above as well as information received from Westcoast and B.C. Gas. Emissions from transmission compressor stations were calculated based on an estimate of compressor station fuel consumption provided by Westcoast and common emission factors produced by the Department of Energy, Mines and Resources (EMR).[4] Distribution emissions are insignificant on a kg/000 m^3 basis but do arise from heater fuel combustion and leakage. EMR's emission rates were also used to estimate air emissions associated with the end use combustion of the gas in the home.[5]

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[1] **Canadian Emissions Inventory of Common Air Contaminants,** March, 1990. Report EPS 5/AP/3.

[2] SC 57-003.

[3] A.P. Jaques, **Greenhouse Gas Emissions: Estimates for Canada,** March 1991, unpublished report. CGA estimated leakages at 0.36% of marketable gas, most of which occurs in processing.

[4] J.A. Coombs, **Greenhouse Gas Emissions Factors by Fuel Type: An Inventory.** Unpublished report, June, 1990.

[5] Air emissions rates for NOx and CO for gas space and water heating appliances produced by the Gas Research Institute were reviewed and found to be similar to the EMR emission factors.

Table 6 shows weighting factors at each stage in the life-cycle which reflect fuel and loss rates. These factors are used to calculate total life-cycle emission rates per thousand cubic metre and input GJ. An annual average loss rate for transmission of 2.0% was used based on Westcoast data. Distribution losses were estimated at .2%.

The estimated life-cycle emissions rates are shown at the bottom of Table 6. CO_2 is clearly the dominant pollutant.

In order to assess the relative importance of different air emissions, estimates of their respective social costs are provided in Table 7. The table lists cost estimates from two U.S. studies that apply different valuation methods. The first study, by Schilberg et al.,[1] uses an abatement cost approach. This approach involves using the marginal cost of pollution controls imposed by regulatory decisions as a proxy for the true social costs imposed by a pollutant. This approach rests upon a number of assumptions including: (1) regulators' choices embody society's preferences for pollution control, (2) the marginal costs of abatement are known, and (3) the abatement costs are incurred solely to reduce emissions of a single pollutant (i.e. that there are no other benefits to a pollution abatement investment). These assumptions are questionable and, therefore, abatement cost estimates must be viewed with caution. Abatement cost is, however, the most common approach in valuing the cost of air emissions.

Schilberg developed social cost estimates in three different regions of the western U.S. to account for differences in air quality. The three regions are: Outside California, Inside California but outside the South Coast Air Quality Management District (SCAQMD) and Inside SCAQMD. Cost estimates are highest Inside SCAQMD due to the air quality problems in the Los Angeles basin. Next highest are the cost estimates for Inside California, but outside SCAQMD, reflecting the significant air quality problems in California centres like the San Francisco Bay Area, though not as severe as in SCAQMD. Cost estimates were lowest for outside California.

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[1] Schilberg, G.M., J.A. Nahigian and W.B. Marcus, Valuing Reductions in Air Emissions and Incorporation into Electric Resource Planning: Theoretical and Quantitative Aspects (re: CEC Docket 88-ER-8), JBS Energy Inc. for the Independent Power Producers, August, 1989.

In this analysis, when using Schilberg's cost estimates, emissions occurring outside the Lower Mainland were costed using the Outside California figures. Emissions occurring inside the Lower Mainland were costed using the Inside California but outside SCAQMD figures. This was done to account for the air quality problems of the Lower Fraser Valley which are similar to those in the San Francisco Bay area.[1] Cost estimates for greenhouse gases are the same in both areas.

Schilberg's cost estimates for SO_2, NO_x, Particulate and VOC's are based on marginal costs of reducing these pollutants at point sources in different areas, using scrubbers or other technology. For CO_2 and CH_4, Schilberg estimates the cost of planting forests in the Pacific Northwest in order to sequester carbon from the atmosphere.[2]

The second set of cost estimates, by researchers at Pace University,[3] are based upon a damage cost approach which is the other principal methodology for calculating social costs. This approach seeks to quantify the estimated economic value of damage caused by air pollutants on their receiving environments. The Pace University study is one of the most comprehensive studies performed to date on the social costs of air emissions. It reviewed a large number of previous studies on damages to the environment, humans and physical structures from various ambient air pollutants and recommended "starting point" social cost figures based on the best information reviewed. In the case of greenhouse gases, a damage cost approach was deemed impossible due to the wide range of impacts of future climate change and associated uncertainties. Instead, Pace reviewed various abatement cost estimates and chose a CO_2 figure that was slightly less than Schilberg's. CH_4 and CO cost estimates were then prorated using this figure and their respective radiative forces relative to CO_2.[1]

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[1] In 1989, The Bay Area had 12 District days when U.S. national air quality standards were exceeded. In the same year, the Greater Vancouver Regional District had at least 8 District days when federal "B"-level air quality objectives were exceeded. No "C"-level exceedances, which are more serious, occurred.

[2] The other greenhouse gas, CO, was costed using Schilberg's CO_2 estimate and a CO radiative force 6 time that of CO_2. Radiative force means the degree to which a molecule of CO traps radiated heat relative to a molecule of CO_2.

[3] Ottinger, R.L., D.R. Wooley, N.A. Robinson, D.R. Hodas, S.E. Babb, Environmental Costs of Electricity. New York: Oceana Publications, 1990.

TABLE 7

Social Cost of Selected Pollutants

(1990 $Cdn/kg)$^+$

	SO_2	NO_x	CO_2	Part.	CH_4	CO	VOC
Schilberg							
Outside Lower Mainland*	1.367	3.690	0.020	--	0.519	0.076	0.902
Inside Lower Mainland**	2.460	25.696	0.020	--	0.519	0.076	1.558
Pace	5.225	2.111	0.017	3.063	0.460	0.065	--

+ Costs computed on the basis of 1989 U.S. inflation at 6.2% from U.S. CPI-U and Canadian-U.S. Exchange rate of 1.17 based on 1990 Bank of Canada Review.

* Based on Schilberg's estimates for outside California

** Based on Schilberg's estimates for inside California but outside the South Coast Air Quality Management District.

The cost estimates for CO_2 are critical in this analysis as they generate a large proportion of the total social costs. A considerable amount of research and debate has focused on what the appropriate social cost of CO_2 and other greenhouse gases should be. To date, using a damage cost approach has been dismissed as impossible because the global consequences of climate change are unknown. Abatement cost estimates for reducing CO_2 emissions by scrubbing are available but have been almost universally dismissed as too costly at $240 per ton of carbon (compared to Schilberg's $54 per ton) and too technically difficult to be practical.[1] A third alternative is to use the cost of a comprehensive package of policies and programs designed to reduce greenhouse gas emissions (such as energy conservation, fuel switching, tree planting, etc.) as a measure of their social cost. This too has been dismissed as being too variable in terms of the policy choices available and their respective costs. For instance, the same mix of policies and programs in different jurisdictions will produce different cost and greenhouse gas impacts due to different energy intensities and physical circumstances.

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[1] The cost estimates for CH_4 and CO reflect radiative forces of 76 and 6 respectively, based on the atomic weight of carbon in each molecule. However, an alternative and arguably more appropriate method to calculate these costs is to base them on the total weight of CH_4 and CO, resulting in costs of $1.266/kg and $1.000/kg respectively. Using this method would increase the environmental cost of gas by less than 6% (the environmental cost of electricity would remain unchanged) and would have little effect on the overall social cost comparisons in this report. See P. Chernick and E. Caverhill, **Report to the Boston Gas Company on Including Externalities in 89-239.** April 12, 1990.

In contrast, tree planting alone provides a more consistent basis for analysis in terms of costs and greenhouse gas impacts. As a result, using the cost of planting trees in order to sequester carbon from the atmosphere as an estimate of the social cost of greenhouse gas emissions has emerged as the most popular approach. Forestry has a number of advantages for valuing social costs, including its independence from fuel and power production, well known costs, proven reliability and the fact that while it is not the sole or complete solution to the problem of global warming, it can significantly delay the effects of climate change.[2]

However, despite the existence of good information on tree planting, social cost estimates for carbon emissions still vary to a considerable degree. Tree planting in Central America has been estimated at between $2.64 and $4.21 per ton of carbon sequestered. Carbon sequestering in North America tree plantations has been estimated at between $40 and $200 per ton of carbon.[1] Schilberg's 2¢/kg cost estimate for CO_2 emissions reflects an abatement cost of $54/ton of carbon, based on the cost of planting trees in the Pacific Northwest. Pace's 1.7¢/kg cost estimate for CO_2 emissions reflects an abatement cost of $47.50/ton of carbon. It was also based on an estimate of tree planting costs in the Pacific Northwest.[2]

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[1] Ottinger, et.al., 1990, p. 140.

[2] Ottinger, et.al., 1990, p. 143.

Various U.S. jurisdictions have adopted social cost estimates of carbon emissions in order to evaluate proposals for new energy supply. Examples include: New York at $7.33 per ton of carbon,[3] California at $26 per ton,[4] Oregon at $40 per ton[5] and Massachusetts and Nevada at $81 per ton.[6] In its most recent review of proposals for new supply, the California Energy Commission used $54 per ton of carbon as the appropriate social cost, the same estimate as Schilberg.[7]

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[1] Chernick, P. and E. Caverhill, **The Valuation of Externalities from Energy Production, Delivery and Use**, A Report to the Boston Gas Company, 1989. Chernick and Caverhill adopt $80 per ton as an appropriate social cost. Using this figure, they estimate the 5.5 billion tons of global fossil fuel carbon emissions to entail a social cost of $440 billion (1989$). They contend that this does not seem to be an unreasonably large estimate of the value of moderating climate change, representing an estimated 2% of current world GNP and 1% of the world GNP in 2025, when serious climate change effects would be predicted by many models.

[2] Pace based its estimate on Buchanan, S., **Costs of Mitigating Greenhouse Effect for Generic Coal, Oil and Gas-Fired Plants.** Unpublished Report, 1989.

[3] New York DPS, **Consideration of Environmental Externalities in Competitive Bidding Program to Acquire Future Electric Capacity Needs of Niagara Mohawk Power Corporation**.

[4] California Energy Commission, **Valuing Emission Reductions for Electricity Report 90.** Staff Issue Paper #3R. Docket #88-ER-8, 1989.

[5] Oregon Department of Energy, **Fourth Biennial Energy Plan**, January, 1991.

[6] Chris Calwell, National Resources Defence Council, personal communication.

[7] Ottinger, et.al., 1990, p. 179.

In Table 8, the emission rates from Table 6 and social costs from Table 7 are combined to estimate the social cost of natural gas in B.C. due to life-cycle air emissions. As shown in the table, the air emission environmental externalities are estimated to total \$2.50/GJ using Schilberg's estimates and \$1.54/GJ using Pace's estimate.[1]

TABLE 8

Air Emission External Cost of Natural Gas

(1990 \$Cdn/input GJ)

	SO2	NOx	CO2	Part.	CH4	CO	VOC	TOTAL
Schilberg	0.10	1.22	1.14	--	0.04	0.00	0.01	2.50
Pace	0.38	0.17	0.96	0.00	0.03	0.00	--	1.54

The main reason for the marked difference in the estimates is the NO_x cost. Schilberg's NO_x cost is based on the marginal cost of reducing NO_x emissions from gas turbines, using selective catalytic reduction technology. In California, substantial NO_x controls are already in effect and, therefore, the marginal cost of further NO_x reductions are quite high. Schilberg's California estimates were used to value the NO_x emissions in the Lower Mainland. Pace, on the other hand, used estimated damage costs on human health, agriculture, physical structures and visibility to value the NO_x emissions. Pace's estimates suggest that the expected damage costs are much lower than the marginal abatement costs in California.

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[1] As noted earlier, this excludes production-related emissions. Based on SO_2 and NO_x emissions estimates in Alberta (ERCB and Alberta Ministries of Energy and Environment), including production could add approximately \$.10/GJ to the cost estimate. However, emissions in B.C. could be quite different because of different gas characteristics and different gathering systems.

For purposes of developing "base case" estimates of air emission external costs, Pace's figures are used. Pace's work is widely recognized as one of the most comprehensive currently available. Also, Pace's damage cost estimates for NO_x may be more appropriate for B.C. than the high marginal abatement costs in California that were estimated by Schilberg. Schilberg's cost estimates are used in section 5.3 for sensitivity test purposes.

3.6 Summary

The economic and environmental costs of gas supply for B.C. Lower Mainland space and water heating applications, as discussed in the previous sections, are summarized in Table 9.

TABLE 9

Natural Gas Economic and Environmental Cost Summary

	Water Heating	Space Heating
Incremental Gas Supply Costs ($/input GJ)	2.91	5.22
Air Emission External Cost ($/input GJ)	1.54	1.54
TOTAL per input/GJ	**4.45**	**6.76**
Efficiency Factors	55%	65% - 90%
TOTAL per output GJ	**8.09**	**10.40 - 7.51**

Taking efficiency factors into account, the total social cost for water heating is estimated at some $8.10 per output GJ. The total social cost for space heating is estimated to range from $10.40 per output GJ for a conventional furnace, to approximately $7.50 per output GJ for a high efficiency condensing furnace.

As noted earlier, while these cost estimates include the estimated social cost associated with air emissions, they do not include the external costs associated with land, water and wildlife impacts. These are difficult to estimate in any general way because of their site-specific nature. To the extent these impacts are largely mitigated by gas producers, processors and transmission companies, the additional external cost they give rise to should be relatively small.

4.0 ECONOMIC AND ENVIRONMENTAL COSTS OF ELECTRICITY

A change in the amount of electricity used for space and water heating would affect electric generation, transmission and distribution requirements and losses for the domestic market, and end use requirements and losses. The economic and environmental costs associated with a change in electricity requirements and losses is discussed below.[1]

4.1 Electric Generation Energy Costs

As discussed in section 2.2, a change in electricity requirements would have quite different impacts in the short and long run. In the short run, with given plant and supply agreements in place, the impacts would primarily be on exports and Burrard thermal production. For example, a reduction in domestic energy requirements due to a shift from electric to gas space and water heating would result in an increase in exports and reduction in thermal production. Over the long term, B.C. Hydro could adjust its expansion and purchase plans. Under its current Resource Plan, a reduction in energy requirements would delay planned expansion of generating facilities at Seven Mile, Waneta and Brilliant, and delay purchases of new IPPs.

Because of the different supply responses, the corresponding cost impacts are quite different. In the short run, the cost saving (or revenue benefit) due to a reduction in domestic energy requirements depends primarily on the fuel cost savings from reduced thermal production and incremental revenues from increased export sales. Over the long term, the cost saving depends on the full cost of the new sources of supply that can be delayed due to the lower load.[2]

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[1] End use equipment costs are addressed in section 5.

[2] The long term marginal cost is based on the cost of new power sources because, with a growing load, they become less expensive than meeting the demand from high cost existing sources (or allowing the probability of not meeting the load and the associated "unserved load" costs to increase).

In Table 10, B.C. Hydro estimates of the marginal energy costs associated with a change in the domestic load are shown for its current Resource Plan.[1] These estimates clearly show the marked differences in the short and long run. Marginal costs in the short to medium term (e.g., to the year 2001) are less than 2.3¢/kwh (in constant 1990$). Over the longer term (e.g. beyond 2005), they increase to over 4¢/kwh (in constant 1990$).

These marginal energy cost estimates include transmission losses to the Lower Mainland, and therefore represent the delivered Lower Mainland energy cost. They were calculated at an 8% real discount rate.

The estimates shown in Table 10 are lower than previous ones developed by B.C. Hydro planning staff. For example, in Hydro's 1990 plan and a cost update reported in April 1991, marginal energy costs had been estimated at 1.8¢/kwh in 1991/92, growing to 5.3¢/kwh by the year 2002-2003.[2]

A number of factors are responsible for the lower current estimates. Firstly, the estimates reported in Table 10 assume much more DSM and self-generation than in the 1990 Plan, or in the April 1991 cost update, and this markedly reduces marginal energy costs in the short to medium term. These sources, if realized, are very cost effective in meeting domestic requirements.

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[1] The estimates are calculated for a 1000 Gwh/year increment of demand over and above the base case forecast. The marginal cost savings from an equivalent decrease in demand would be somewhat less than the estimates shown in Table 10.

[2] B.C. Hydro, **The Cost of New Electricity Supply in British Columbia**, December, 1990, Exhibit 1, p. 2; **Electricity Cost Update: The Cost of New Electricity Supply in British Columbia 1991 Update**, April, 1991.

TABLE 10

Marginal Electric Energy Costs*

(¢/kwh in constant 1990$)

Year	Marginal Cost
1991-92	1.68
1992-93	1.82
1993-94	1.86
1994-95	1.92
1995-96	2.02
1996-97	2.05
1997-98	2.02
1998-99	2.16
1999-00	1.92
2000-01	2.27
2001-02	2.70
2002-03	3.26
2003-04	3.17
2004-05	3.75
2005-06	4.39
2006-07	4.64
2007-08	4.46
2008-09	4.30
2009-10	4.22
2010-11	4.15

*Including losses to the Lower Mainland
Source: B.C. Hydro Planning Staff

Secondly, the estimates in Table 10 assume the repatriation of the downstream benefits under the Columbia River Treaty, starting in 1998. This serves to reduce marginal costs of supply as they come on-stream; they also delay the need for more expensive new sources of supply at the end of the planning period.[1]

Of course, not all of the assumptions in the current plan may prove correct. DSM may not be realized to the full extent currently assumed, or requirements may grow more rapidly than currently forecast. The downstream benefits may not be used to meet B.C. requirements; they could be exported, increasing B.C. Hydro's generation requirements and marginal costs. Indeed, one of the factors contributing to the low marginal cost estimates is provincial government policy restricting firm exports. The prices available from such exports could well raise the opportunity cost of domestic sales.

On the other hand, the avoided costs due to reductions in demand are less than the marginal increase in costs associated with increased demand. In that respect, the estimates in Table 10 may overstate, at least to some extent, the marginal cost savings that could result from a shift to natural gas space and water heating. Also, the estimates include water rentals and other taxes paid by B.C. Hydro which serves to overstate the real costs from a provincial perspective.[2]

In short, there is some uncertainty. Nevertheless, the pattern is clear. Marginal energy costs are quite low in the short term and will remain so until major new sources of supply are required or major new, high-valued, export opportunities become available to B.C.

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[1] The 5.3¢/kwh marginal energy cost that had been estimated for 2002-03 under the 1990 plan and the April 1991 update was in fact a weighted average cost of major new hydro projects, scheduled to begin to come on-stream at that time. It was intended to reflect an average long term cost of firm energy from new projects (Ibid., Exhibit 6, p. 8). Because of the greater reliance on IPPs (and DSM and the downstream benefits), incremental requirements do not have to be met by major new hydro sources over the planning period in the current plan.

[2] These taxes constitute transfers to the province, not a social cost. The principal tax is the water rental, estimated at .4¢/kwh of hydro production. Because hydro is not a major marginal source of supply, particularly in the short to medium term, the impact of including taxes is relatively small.

4.2 Electric Capacity Costs

A change in electricity requirements not only affects the amount of energy (kwh) that B.C. Hydro must supply, but also the amount of generating and transmission capacity (kw) it must have to meet peak demands.

In the short term, B.C. Hydro has more capacity than required for the domestic market, and the marginal costs of peak requirements are measured by the value of capacity in the export market. Over the medium to long term, the marginal costs are measured by the costs of new transmission and generating capacity required to meet increased demand.

B.C. Hydro's latest electricity cost studies indicate that the current marginal cost of capacity for deliveries to the Lower Mainland market are in the order of $35/kw.[1] This is expected to increase to $56/kw by the end of the decade, as shown in Table 11.

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[1] The current estimates are higher than those estimated in 1990 because of much higher estimated values of capacity in the export market.

TABLE 11

Marginal Electric Capacity Costs*

	Cost/kw ($)	Average Cost @ 77% L.F (¢/kwh)	Average Cost @ 30% L.F. (¢/kwh)
1991-92	35	.52	1.33
1992-93	36	.53	1.37
1993-94	37	.55	1.41
1994-95	38	.56	1.45
1995-96	43	.64	1.64
1996-97	47	.70	1.79
1997-98	52	.77	1.98
1998-99	56	.83	2.13
1999-2000⁺	56	.83	2.13

*Costs of capacity, including losses, for the Lower Mainland.
Source: B.C. Hydro Planning Staff

In Table 11, the costs per kwh are shown at 77% and 30% load factors. The 77% load factor is representative of water heating loads; 30% is representative of space heating loads.[1]

4.3 Electricity Distribution Costs and Losses

The impact of a change in electricity requirements on distribution costs depends on its effect on the distribution system. Differences in the intensity of use that would affect the system design for new areas or require modifications for existing ones would have marginal cost implications. If there were no system effects, the marginal costs would be zero.

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[1] See Marbek, **Electricity Consumption and Acid Rain in Ontario**, prepared for Ontario Ministry of Energy, 1989 and P. Chernick, et. al., **Analysis of Residential Fuel Switching as an Electricity Conservation Option**, September, 1990.

In its latest long run incremental cost study, B.C. Hydro estimated the distribution requirement and cost implications of serving an added load for existing customers, i.e. an increased intensity of use. Though clearly this could vary in specific circumstances, Hydro estimated there would be a change in distribution capital and operating costs as a result of more intensive use. The average long run incremental cost was estimated at $31/kw.[1] At a load factor of 77%, this would amount to .46¢/kwh. At a load factor of 30%, this would amount to 1.18¢/kwh.

The incremental cost study also provides estimates of loss rates. Distribution losses to residential customers (from the transmission or bulk level) are estimated at 7.46% for capacity and 6.17% for energy.[2]

4.4 Electricity Supply Cost Summary

In Table 12, the marginal electric generation, transmission and distribution costs, as discussed above, are summarized. The energy and generation/transmission capacity costs have been adjusted to take into account distribution losses. No efficiency losses are assumed for space heating applications but an 82% efficiency factor is assumed for hot water when calculating total costs on an output energy basis.[3]

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[1] B.C. Hydro, Long Run Incremental Cost of Service Study, Rate Design Application, January 1991, Schedule 4, p. 2.

[2] Ibid., Schedule 3. These rates were calculated by dividing total residential loss multipliers by the transmission customer loss multipliers.

[3] Based on B.C. Hydro estimates. 100% space heating efficiency reflects electric furnaces. Baseboards could have an efficiency factor greater than 100% because of the zone control they offer.

TABLE 12

Electricity Supply Cost Summary

Year	Generation Energy (¢/kwh)	Generation/ Transmission Capacity ($/kw)	Distribution ($/kw)	Total Supply Cost for Water Heating*		Total Supply Cost for Space Heating** (¢/kwh)
				¢/input kwh	¢/output kwh	
1991-92	1.78	37.61	31	2.80	3.41	4.39
1992-93	1.93	38.69	31	2.96	3.61	4.58
1993-94	1.97	39.76	31	3.02	3.68	4.66
1994-95	2.04	40.83	31	3.10	3.78	4.77
1995-96	2.14	46.21	31	3.28	4.00	5.08
1996-97	2.18	50.51	31	3.39	4.13	5.28
1997-98	2.14	55.88	31	3.43	4.18	5.45
1998-99	2.29	60.18	31	3.64	4.44	5.76
1999-00	2.04	60.18	31	3.39	4.13	5.51
2000-01	2.41	60.18	31	3.76	4.59	5.88
2001-02	2.87	60.18	31	4.22	5.15	6.34
2002-03	3.46	60.18	31	4.81	5.87	6.93
2003-04	3.37	60.18	31	4.72	5.76	6.84
2004-05	3.98	60.18	31	5.33	6.50	7.45
2005-06	4.66	60.18	31	6.01	7.33	8.13
2006-07	4.93	60.18	31	6.28	7.66	8.40
2007-08	4.74	60.18	31	6.09	7.43	8.21
2008-09	4.57	60.18	31	5.92	7.22	8.04
2009-10	4.48	60.18	31	5.83	7.11	7.95
2010-11	4.41	60.18	31	5.76	7.02	7.88

* Based on 77% load factor. Costs per output kwh based on an 82% efficiency factor.

** Based on a 30% load factor. No efficiency losses are assumed.

The table shows the total costs per kwh, with the capacity charges per kwh based on 77% and 30% load factors, the former being representative of a water heating load and the latter representative of a space heating load.

4.5 External Effects

As with natural gas, an increase or decrease in electricity consumption in British Columbia has a number of environmental impacts not reflected in the supply costs discussed above. There are air quality impacts associated with thermal power generation and potential land use, fisheries, wildlife and other resource impacts associated with new hydro development. The development of new power lines can have land use and wildlife impacts as well as raise concerns about possible electromagnetic radiation.

The land use and other potential impacts of new hydro or power line developments are site specific and no attempt is made here to quantify the associated costs.[1] However, air quality impacts of a change in B.C. electricity consumption are identified and the associated costs estimated. Given the nature of the B.C Hydro plan, changes in electricity consumption in the short to medium term will primarily affect thermal production in B.C. and elsewhere, and thus the air quality impacts are the most significant environmental effects. Over the long term there will be changes in the timing of some hydro developments and IPP purchases, but the hydro projects entail additions of capacity to existing facilities with limited effects. The nature and location of the IPPs are unknown at this time.

In order to identify the impacts of a change in electricity consumption on thermal power production and related air quality effects, B.C. Hydro simulations of their Resource Planning Model with their current base case and a 5% reduced load were used. As noted earlier, the principal effects of a reduced load are to reduce Burrard thermal production and to increase exports. There is also some reduction in imports from, and an increase in exports to, Alberta. The increased exports to the U.S. have the effect of reducing oil and gas-fired thermal generation in California and coal-fired generation in the Pacific Northwest. The reduction in imports and increase in exports to Alberta have the effect of reducing coal and gas-fired production in that province.

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[1] As with natural gas, this may serve to understate the total external cost associated with a change in electricity use.

Table 13 shows the estimated reduction in thermal production in B.C. and elsewhere, due to a 5% reduction in B.C.'s load. The estimates for California and the Pacific Northwest are based on the estimated impact on exports, adjusted for estimated transmission losses in the U.S. The impacts are reported for three selected years: 1994, 1999 and 2004. After 2004, reductions in the net load affect the timing and amount of new sources of supply -- not just production from existing facilities.

TABLE 13

Impacts on Thermal Generation in B.C. and Elsewhere due to a 5% Reduction in B.C.'s Load

(Gwh)

	California*	Pacific Northwest**	Burrard	Alberta
1994	(1114)	(173)	(694)	(214)
1999	(1114)	(267)	(654)	(145)
2004	(1343)	(171)	(671)	(273)

* Assumes a 4.9% transmission loss.
** Assumes a 1.9% transmission loss.
Source: B.C. Hydro Resource Planning Model.

The largest impacts occur in California which receives electricity from B.C. both directly and indirectly via the Pacific Northwest. Oil and gas thermal generation throughout the state[1] is displaced by the incremental exports from British Columbia.

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[1] In this analysis, it is estimated that 50% of the displaced generation is in Northern California, 25% in Sacramento and 25% in Southern California, based on information from Powerex.

Exports to the Pacific Northwest primarily displace coal fired generation at the Boardman plant operated by Portland General Electric.

The impacts of reduced thermal production on air pollution depend on the emission rates in the affected plants. In Table 14, estimated emission rates are shown for oil and gas plants in California, the Boardman plant in the Pacific Northwest, the Burrard plant in B.C. and gas and coal plants in Alberta. For both California and Alberta, average system-wide rates are reported because it was not possible to identify the specific plants that would be affected by a change in B.C. supply.

TABLE 14

Emission Rates from Thermal Generation

(tonnes/Gwh)

	SO_2	NO_x	CO_2	Partic.	CH_4	CO	VOC's
California[1] - Oil & Gas	0.222	0.833	545	0.036	0.010	0.171	0.004
U.S. PNW[2] - Coal	6.150	3.580	1,129	0.210	0.010	0.960	0.030
Burrard[3] - Gas	0.006	0.400	600	0.007	0.013	0.206	0.012
Alberta							
- Gas	0.023	0.834	678	0.000	0.017	0.270	0.016
- Coal	2.800	1.900	1,007	0.759	0.005	0.854	0.016
- Weighted Average[4]	2.500	1.734	963	0.676	0.007	0.780	0.016

[1] Assumes 11% oil and 89% gas production based on 1989 Pacific Gas & Electric experience. SO_2, NO_x, Particulate, CO and VOC from Ted Holcombe, Pacific Gas and Electric. CO_2 and CH_4 from emission factors.

[2] Emissions from Boardman coal-fired thermal plant. SO_2, NO_x, and Particulate from Terry Warrell, Portland General Electric. CO_2, CH_4, CO and VOC from emission factors.

[3] SO_2, NO_x, CO_2 and Particulate from Al Brotherston, B.C. Hydro. CH_4, CO and VOC from emission factors.

[4] Assumes 86.8% coal and 13.2% gas production based on 1989 experience. SO_2 and NO_x from Energy Resources Conservation Board, **Alberta Electric Industry Annual Statistics, 1990**. CO_2, Particulate, CH_4, CO and VOC from emission factors.

The emission rates vary by jurisdiction because of differences in fuel type and plant characteristics. Despite the fact that 11% of its thermal power comes from oil, California's emission rates are generally the lowest because of its larger, more efficient boilers and because of its strict air emission standards. The US Pacific Northwest has high SO_2 emission rates because of the sulphur content of the coal burned by Boardman. Burrard has low emissions of NO_x relative to the US or Alberta because of its tangential boiler design. In Alberta, gas-fired thermal plants have lower emission rates than the coal-fired plants, except for methane and volatile organic compounds.

In order to assess the significance of the air emissions impacts, the estimated reductions are valued using the same social cost estimates as reported and discussed in section 3.5. The two sets of cost estimates are reproduced in Table 15. Schilberg's cost estimates for Inside the South Coast Air Quality Management District are also shown because some of the impacts occur in that area.

TABLE 15

Social Cost of Selected Pollutants

(1990 $Cdn/kg)

	SO_2	NO_x	CO_2	Part.	CH_4	CO	VOC
Schilberg							
Outside California	1.367	3.690	0.020	--	0.519	0.076	0.902
California Outside SCAQMD	2.460	25.696	0.020	--	0.519	0.076	1.558
Inside SCAQMD	25.010	33.5	0.020	--	0.519	0.076	23.919
Pace	5.225	2.111	0.017	3.063	0.460	0.065	--

Table 16 shows the estimated annual value of the reduced air emissions due to a 5% reduction in B.C.'s load, based on Schilberg and Pace's social cost estimates and the thermal production and emission rate estimates reported earlier. When applying Schilberg's estimates, it was assumed that 25% of the California impacts would be in the SCAQMD. Burrard impacts were valued using the inside California, outside SCAQMD estimates because of the similarity in air quality problems between the lower Fraser Valley and the San Francisco Bay Area. Alberta and PNW impacts were valued using the outside California estimates.

Based on Schilberg's estimates, a 5% reduction in B.C.'s load generates a total of over $68 million in environmental benefits in 1994 due to reduced air emissions in the various jurisdictions. This total increases to $70 million and $71 million in 1999 and 2004 respectively. In terms of specific pollutants, the greatest benefits are associated with reduced emissions of NO_x and CO_2. Total NO_x benefits are high because most emission reductions occur in California where NO_x has a high social cost. While CO_2 is associated with a relatively low social cost per kg, the large volume of emissions results in a high total value.

Pace's social cost estimates suggest lower total benefits than Schilberg's. A large percentage of the difference between total costs from Pace and Schilberg is due to the difference between their NO_x cost estimates.

The environmental benefits reported in Table 16 occur in a number of jurisdictions. Some might argue that only the benefits associated with reduced air emissions in B.C. (resulting from the reduced production at Burrard) are relevant from a B.C. perspective. A more defensible position would be that the benefits associated with reduced air emissions in B.C. plus the benefits associated with reduced emissions of greenhouse gases in all jurisdictions are of concern to B.C. Some would argue that all emissions in all jurisdictions are of concern to B.C.

TABLE 16

Annual Value of Air Emissions Reductions Due to a 5% Reduction in B.C. Hydro's Net Load

- Selected Years -

(000's 1990 Cdn.$)*

Based on Costs from Schilberg

Year		SO_2	NO_x	CO_2	Particulate	CH_4	CO	VOC	TOTAL
1994	California	2002	25643	12208	--	6	5	32	39896
	PNW	1452	2281	3918	--	1	5	5	7661
	Burrard	10	7133	8370	--	5	4	13	15535
	Alberta	423	1086	3637	--	1	3	3	5153
	TOTAL	3887	36143	28132	--	13	18	53	68245
1999	TOTAL	4498	36576	28535	--	13	19	53	69693
2004	TOTAL	3256	39570	28075	--	13	16	55	70985

Based on Costs from Pace

Year		SO_2	NO_x	CO_2	Particulate	CH_4	CO	VOC	TOTAL
1994	California	1292	1958	10118	123	5	4	--	13501
	PNW	5548	1305	3248	111	1	4	--	10216
	Burrard	22	586	6937	15	4	3	--	7567
	Alberta	1616	621	3015	255	1	3	--	5511
	TOTAL	8478	4470	23318	504	11	15	--	36795
1999	TOTAL	10815	4919	23651	454	11	15	--	39866
2004	TOTAL	4758	3930	23270	603	11	13	--	32585

*Schilberg's cost estimates were inflated by 6.2% for 1989 U.S. inflation from U.S. CPI-U. Both cost estimates were translated into Canadian dollars using an exchange rate of 1.17 from the Bank of Canada Review, 1990.

In Table 17, the benefits from all three perspectives (B.C., B.C. plus all greenhouse, all emissions) are shown. They are reported on a cents per kwh basis, reflecting the estimated total benefits shown in Table 16 divided by the assumed reduction in B.C. load. As such, they indicate the air emission environmental benefits per unit reduction in input energy requirements in B.C. One can assume they would be similar to the increase in air emission costs that would occur per unit increase in input requirements. In other words, they represent marginal air emissions external costs per input kwh.

TABLE 17

Air Emission Environmental Benefits per Unit Reduction in B.C. Demand*

- Selected Years -

(¢/kwh)

Based on Costs from Schilberg

	B.C. Emissions	B.C. Plus Greenhouse Emissions	All Emissions
1994	0.6	1.4	2.6
1999	0.5	1.2	2.4
2004	0.5	1.1	2.1

Based on Costs from Pace

	B.C. Emissions	B.C. Plus Greenhouse Emissions	All Emissions
1994	0.3	0.9	1.4
1999	0.3	0.8	1.4
2004	0.2	0.7	1.0

*Assumed to reflect marginal air emission external costs per kwh of increased electricity use

The marginal air emission environmental benefits of reduced B.C. demand (or marginal costs due to increased demand) are relatively small when based only on B.C. emissions. That is because so much of the electricity production impacts resulting from a change in B.C. demand occur outside the province. Including the value of the greenhouse emission impacts outside the province more than doubles the estimates. Including the value of all emission impacts outside the province raises the estimates further, primarily because of the NO_x and SO_2 impacts in other jurisdictions.

Pace's estimates for B.C. emissions plus all greenhouse gas emissions suggest marginal air emission external costs of .9¢/kwh in 1994 falling to .7¢/kwh in the year 2004. The different annual values are due to the different mix of production impacts in the different years. Over the three years shown, Pace's estimates for B.C. plus all greenhouse emissions average .8¢/kwh. This average value is used for the base case social cost comparisons in this study. Schilberg's estimates are considered in section 5.3 for sensitivity test purposes. The B.C. plus all greenhouse emission estimates are used (as opposed to the B.C. only or all emission estimates) because they are considered most relevant from the perspective of British Columbia.[1] A single average value (as opposed to varying annual estimates) is used because of the uncertainty in the estimates.

4.6 Summary

The total marginal economic and environmental costs of electricity supply, as discussed in the previous sections, are summarized in Table 18. The results are reported per input kwh. For space heating, with an assumed 100% efficiency factor, the costs per output kwh would be the same. For water heating, the efficiency factor is estimated at 82%. The costs per output kwh would therefore be higher by a factor of 1/.82.

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[1] While some would argue that environmental impacts in all jurisdictions are relevant to B.C., the impacts outside the province might simply entail a different level of abatement costs, not emissions. It is not clear why such costs or benefits accruing to business and people in other jurisdictions should be included in an evaluation of alternative fuel costs in B.C.

TABLE 18

Economic and Environmental Cost Summary

(¢/input kwh)

Year	Water Heating			Space Heating		
	Gen./Trans./ Distribution	Air Emission External	Total	Gen./Trans./ Distribution	Air Emission External	Total
1991-92	2.80	.8	3.60	4.39	.8	5.19
1992-93	2.96	.8	3.76	4.58	.8	5.38
1993-94	3.02	.8	3.82	4.66	.8	5.46
1994-95	3.10	.8	3.90	4.77	.8	5.57
1995-96	3.28	.8	4.08	5.08	.8	5.88
1996-97	3.39	.8	4.19	5.28	.8	6.08
1997-98	3.43	.8	4.23	5.45	.8	6.25
1998-99	3.64	.8	4.44	5.76	.8	6.56
1999-00	3.39	.8	4.19	5.51	.8	6.31
2000-01	3.76	.8	4.56	5.88	.8	6.68
2001-02	4.22	.8	5.02	6.34	.8	7.14
2002-03	4.81	.8	5.61	6.93	.8	7.73
2003-04	4.72	.8	5.52	6.84	.8	7.64
2004-05	5.33	.8	6.13	7.45	.8	8.25
2005-06	6.01	.8	6.81	8.13	.8	8.93
2006-07	6.28	.8	7.08	8.40	.8	9.20
2007-08	6.09	.8	6.89	8.21	.8	9.01
2008-09	5.92	.8	6.72	8.04	.8	8.84
2009-10	5.83	.8	6.63	7.95	.8	8.75
2010-11	5.76	.8	6.56	7.88	.8	8.68

The total marginal costs for water heating loads are estimated to increase from a current level of 3.6¢ per input kwh (or 4.4¢ per output kwh taking appliance efficiencies into account) to over 6.6¢ per input kwh (8.0¢ per output kwh) in the year

2010. The total costs for space heating loads are expected to increase from 5.2¢ to 8.7¢ per input and output[1] kwh over this period.

The relatively low current cost is due to B.C. Hydro's surplus and the low cost demand and supply options currently available to B.C. Hydro. The higher costs in the future result from the elimination of the surplus and the need to pursue more expensive supply alternatives.

As with natural gas, these cost estimates do not include the environmental external costs associated with land, water, wildlife or other non-air emission-related impacts. This is probably not too significant in the short to medium term, because the marginal sources of supply are existing thermal (in B.C. or elsewhere). However, the external costs could be significantly understated over the longer term, when the timing or need for hydro and other new sources of supply would be affected.

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[1] An efficiency factor of 100% is assumed.

5.0 SUBSTITUTION OF GAS FOR ELECTRICITY - SOCIAL COST COMPARISONS

5.1 Water Heating Loads

The economic and environmental costs of natural gas and electricity provide measures of their social cost -- i.e. the costs of these fuels borne by all British Columbians as opposed to the private cost or price paid by individual users. In Table 19, the social cost estimates for gas and electric water heating loads are presented and compared. All of the estimates are reported in constant 1990 dollars per output GJ.[1]

As shown in the table, the cost of gas is lower than electricity. The difference is estimated at $4.19/GJ in 1991, increasing to $7.45/GJ by the year 2000 and $14.23/GJ by the year 2010.

All of the estimated difference is due to the energy supply (or "economic") cost. The external costs of gas and electricity are estimated to be virtually the same. Because the estimates only take air emissions into account, one might have thought that gas would have exhibited higher external costs. However, in the short to medium term the marginal sources of electricity are thermal-generated power, giving rise to considerable air emissions. Indeed, it is only because much of the thermal power impacts occur outside the province that the costs associated with electricity (with its lower combustion efficiency than direct gas use) are not greater than natural gas.[2]

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[1] A conversion factor of .0036 GJ/kwh is used for the electricity cost estimates.

[2] Also, the electricity air emissions were calculated only for the combustion of fuels in thermal power production, excluding the emissions from the production, processing and transportation of the fuels. This serves to underestimate the full fuel cycle electricity costs.

TABLE 19

Water Heating Cost Comparison

($/output GJ)

Year	ENERGY SUPPLY			EXTERNAL COST			TOTAL		
	Gas	Electricity	Difference (Gas-Elect.)	Gas	Electricity	Difference (Gas-Elect.)	Gas	Electricity	Difference (Gas-Elect.)
1991	5.28	9.48	(4.20)	2.81	2.80	0.01	8.09	12.28	(4.19)
1992	5.28	10.04	(4.76)	2.81	2.80	0.01	8.09	12.84	(4.75)
1993	5.28	10.23	(4.95)	2.81	2.80	0.01	8.09	13.03	(4.94)
1994	5.28	10.52	(5.24)	2.81	2.80	0.01	8.09	13.32	(5.23)
1995	5.28	11.13	(5.85)	2.81	2.80	0.01	8.09	13.93	(5.84)
1996	5.28	11.48	(6.20)	2.81	2.80	0.01	8.09	14.28	(6.19)
1997	5.28	11.61	(6.33)	2.81	2.80	0.01	8.09	14.41	(6.32)
1998	5.28	12.34	(7.06)	2.81	2.80	0.01	8.09	15.14	(7.05)
1999	5.28	11.49	(6.21)	2.81	2.80	0.01	8.09	14.29	(6.20)
2000	5.28	12.74	(7.46)	2.81	2.80	0.01	8.09	15.54	(7.45)
2001	5.28	14.30	(9.02)	2.81	2.80	0.01	8.09	17.10	(9.01)
2002	5.28	16.30	(11.02)	2.81	2.80	0.01	8.09	19.10	(11.01)
2003	5.28	16.00	(10.72)	2.81	2.80	0.01	8.09	18.80	(10.71)
2004	5.28	18.06	(12.78)	2.81	2.80	0.01	8.09	20.86	(12.77)
2005	5.28	20.37	(15.09)	2.81	2.80	0.01	8.09	23.17	(15.08)
2006	5.28	21.28	(16.00)	2.81	2.80	0.01	8.09	24.08	(15.99)
2007	5.28	20.64	(15.36)	2.81	2.80	0.01	8.09	23.44	(15.35)
2008	5.28	20.06	(14.78)	2.81	2.80	0.01	8.09	22.86	(14.77)
2009	5.28	19.76	(14.48)	2.81	2.80	0.01	8.09	22.56	(14.47)
2010	5.28	19.52	(14.24)	2.81	2.80	0.01	8.09	22.32	(14.23)

In Table 20, the annual savings using gas for a typical water heating load are shown. The estimates are based on an average requirement of 14.76 output GJ per year.[1]

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[1] Based on estimates provided by B.C. Hydro staff.

The present value savings, calculated over a 10 year appliance life at an 8% real discount rate, are estimated to total some $600. This fuel cost saving indicates the maximum amount that could be invested in equipment to use gas as opposed to electricity, and still leave gas as the most socially cost effective fuel.

TABLE 20

Water Heating Savings Using Gas

(Constant 1990$)

Year	Savings
1991	61.79
1992	70.09
1993	72.88
1994	77.17
1995	86.16
1996	91.35
1997	93.33
1998	104.02
1999	91.52
2000	110.02
Present Value (@ 8%)	**599.90**

In the context of a new installation, or required replacement of old appliances, the social fuel cost advantage of gas favours the purchase of a gas hot water heater. Lower Mainland appliance dealers indicate that the cost of purchasing and installing a gas hot water heater is roughly the same as an electric one. In other words, the incremental cost to use gas is zero.

The net benefits of converting to gas, however, are less clear. If the conversion means abandoning a perfectly functioning, relatively new electric heater, the incremental capital cost is measured by the full cost of buying and installing the gas heater. B.C. Hydro staff estimate the average cost of converting from electric to gas water heating at $650 to $775.[1] This exceeds the expected fuel cost saving of some $600. Only if the conversion meant that electric equipment costs are avoided could the fuel savings exceed the incremental capital costs.

In sum, gas is a preferred energy source in terms of its social cost. However, if a decision to use electricity for water heating has already been made, the capital costs of conversion will exceed the fuel cost saving. Only when the electric appliance is nearing need of replacement will conversion clearly be economic.

5.2 Space Heating Loads

In Table 21, the social cost estimates for gas and electricity space heating loads are presented and compared on an output GJ basis. Three estimates for gas costs are shown, corresponding to conventional, intermediate and high efficiency furnaces.

In all cases, the social cost of gas is less than electricity, with the difference growing over the next twenty years. The cost advantage for gas (on an output GJ basis) is, of course, greater with the higher efficiency furnaces.

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[1] Estimates from local appliance dealers ranged from $640 to $1000, depending on the size of the tank.

TABLE 21

Space Heating Cost Comparison*

($/output GJ)

Year	Gas			Electricity	Difference		
	Conventional	Intermediate	High Efficiency		Conventional	Intermediate	High Efficiency
1991	10.40	8.45	7.51	14.49	(4.09)	(6.04)	(6.98)
1992	10.40	8.45	7.51	15.02	(4.62)	(6.57)	(7.51)
1993	10.40	8.45	7.51	15.25	(4.85)	(6.80)	(7.74)
1994	10.40	8.45	7.51	15.56	(5.16)	(7.11)	(8.05)
1995	10.40	8.45	7.51	16.40	(6.00)	(7.95)	(8.89)
1996	10.40	8.45	7.51	16.97	(6.57)	(8.52)	(9.46)
1997	10.40	8.45	7.51	17.42	(7.02)	(8.97)	(9.91)
1998	10.40	8.45	7.51	18.30	(7.90)	(9.85)	(10.79)
1999	10.40	8.45	7.51	17.60	(7.20)	(9.15)	(10.09)
2000	10.40	8.45	7.51	18.63	(8.23)	(10.18)	(11.12)
2001	10.40	8.45	7.51	19.91	(9.51)	(11.46)	(12.40)
2002	10.40	8.45	7.51	21.55	(11.15)	(13.10)	(14.04)
2003	10.40	8.45	7.51	21.30	(10.90)	(12.85)	(13.79)
2004	10.40	8.45	7.51	22.99	(12.59)	(14.54)	(15.48)
2005	10.40	8.45	7.51	24.88	(14.48)	(16.43)	(17.37)
2006	10.40	8.45	7.51	25.63	(15.23)	(17.18)	(18.12)
2007	10.40	8.45	7.51	25.10	(14.70)	(16.65)	(17.59)
2008	10.40	8.45	7.51	24.63	(14.23)	(16.18)	(17.12)
2009	10.40	8.45	7.51	24.38	(13.98)	(15.93)	(16.87)
2010	10.40	8.45	7.51	24.18	(13.78)	(15.73)	(16.67)

* Includes both energy supply and external costs.

The energy supply and external cost components of the total social costs are not shown in the table. However, most of the difference in the total costs is due to the costs of energy supply. The estimated external costs for gas and electricity are quite similar.

In Table 22, the annual savings using gas for a typical single detached space heating load are shown. The estimates are based on an average requirement of 34.26 output GJ year.[1] The present value savings are calculated at an 8% real discount rate over an estimated twenty year life.

The present value savings are much larger than for water heating because of the larger load and longer appliance life. Over a twenty year period, the cost savings using gas total $2900 for a conventional furnace, $3600 for an intermediate furnace and almost $4000 for a high efficiency furnace.

The cost advantage for gas clearly favours installation of gas heating in new housing. It could also favour conversion to gas in currently electrically heated homes. The cost of gas furnaces are significantly less than the fuel cost savings. Purchase and installation costs were estimated by one contractor to total $1200 for a conventional (100,000 BTU) furnace, $1800 for an intermediate furnace and $3200 for a high efficiency furnace.[2] Where ducting already exists or does not entail prohibitive costs,[3] conversions could be undertaken with positive net benefits.

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[1] Based on estimates provided by B.C. Hydro staff.

[2] B.C. Hydro staff estimate the cost of a conventional furnace at $1500 and an intermediate furnace at $2000.

[3] Heating contractors indicated that ducting could be installed relatively simply in one storey dwellings with a crawl space or basement.

TABLE 22

Space Heating Savings Using Gas

(Constant 1990$)

Year	Conventional	Intermediate	High Efficiency
1991	140.26	207.07	239.23
1992	158.45	225.25	257.42
1993	166.13	232.93	265.10
1994	176.67	243.47	275.64
1995	205.67	272.47	304.64
1996	225.04	291.85	324.01
1997	240.68	307.49	339.65
1998	270.53	337.33	369.50
1999	246.74	313.54	345.71
2000	281.95	348.75	380.92
2001	325.73	392.53	424.70
2002	381.87	448.68	480.84
2003	373.31	440.11	472.28
2004	431.36	498.17	530.33
2005	496.07	562.88	595.04
2006	521.77	588.57	620.74
2007	503.69	570.49	602.66
2008	487.51	554.31	586.48
2009	478.94	545.75	577.91
2010	472.28	539.09	571.25
Present Value @ 8%	2,920.81	3,629.18	3,970.24

5.3 Sensitivity Tests

The social cost comparisons in the previous two sections are based on numerous estimates and assumptions, many of which are subject to considerable uncertainty. The sensitivity of the results to some of the more critical values are described below.

5.3.1 Alternative Production Cost Estimates

Two sensitivity cases were considered with respect to production costs. For gas, a case reflecting the common assumption of rising replacement costs was considered, wherein it was assumed that the production cost or wellhead value of the gas increases at a real rate of 4% per year. For electricity, a case incorporating higher energy costs was considered, using B.C. Hydro's 1991 incremental energy cost estimates based on the assumption of no access to the downstream benefits from the Columbia River Treaty.[1] Energy costs increase to a long run incremental cost of 5.3¢ per kwh by the year 2002 in this case.

In Table 23, the effect of these alternative assumptions on the present value savings using gas for water and space heating are shown.

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[1] See B.C. Hydro, Electricity Cost Update: The Cost of New Electricity Supply in British Columbia 1991 Update.

TABLE 23

Present Value Savings Using Gas

- Production Costs Sensitivity Cases -*

(Constant 1990$)

	Base Case	Higher Gas Cost	Higher Electricity Cost
Water Heating	599.90	552.24	726.98
Space Heating (Conventional Furnace)	2,920.81	2,641.37	3,631.69

* Calculated at an 8% real discount rate over ten years for water and twenty years for space heating.

The impact of the rising gas cost assumption is small, reducing somewhat the savings using gas. The impact of the alternative electricity cost assumption is more marked, increasing the cost advantage of using gas. This would increase the likelihood or circumstances under which conversions to gas would be economic.

5.3.2 Alternative Environmental Cost Estimates

Three sensitivity cases were considered with respect to the environmental cost estimates. In one case, Schilberg's abatement cost estimates were used instead of Pace's damage cost estimates. In the second, Pace's estimates were retained, but the marginal environmental costs of electricity were defined to include the effects of all emissions in all jurisdictions. In the third, an estimate of the air emission costs associated with gas production is included, based on emissions data compiled by the Alberta government and ERCB on Alberta gas fields.

The impacts of the alternative assumptions on the present value savings using gas are shown in Table 24.

TABLE 24

Present Value Savings Using Gas

- Environmental Cost Sensitivity Cases -*

(Constant 1990$)

	Base Case	**Schilberg Estimates**	**Pace Including Emission Impacts in all Jurisdictions**	**Pace Including Gas Production Emissions**
Water Heating	599.90	552.83	756.80	579.36
Space Heating (Conventional Furnace)	2,920.81	2,773.19	3,357.75	2,861.75

* Calculated at an 8% real discount rate over ten years for water and twenty years for space heating.

The use of Schilberg's cost estimates raises external costs for both gas and electricity. The net effect, however, is relatively small, reducing the savings using gas. Including emission impacts in all jurisdictions raises the marginal environmental costs of electricity. This significantly increases the social cost advantage of using gas, again increasing the likelihood of conversions being economic. The inclusion of gas production air emission costs has only a limited effect, reducing the cost advantage of using gas by a small amount.

5.3.3 Discount Rate

Two alternative discount rates were used to calculate the present value savings using gas: 6% and 10% real. As shown in Table 25, the present value savings increase with the lower rate and fall with the higher discount rate. This occurs because of the effect that the discount rate has on the weight given to future fuel cost savings.

TABLE 25

Present Value Savings Using Gas

- Discount Rate Sensitivity Cases -

(Constant 1990$)

	6%	8% Base Case	10%
Water Heating	651.57	599.90	554.69
Space Heating (Conventional Furnace)	3,499.43	2,920.81	2,472.20

5.3.4 Efficiency Factor

In one final sensitivity case, the efficiency for electric space heating was assumed to be 106%, based on the zone control offered by baseboard heating. This reduced the present value savings using gas for space heating (with a conventional furnace) from $2900 to $2500.

5.4 Summary

It is clear that the social cost of natural gas is less than electricity for lower Mainland space and water heating applications. Whether the cost savings are sufficient to justify conversions to gas are less clear. Under the base case set of assumptions, water heater conversions would only be economic if the existing electric heaters would soon need replacement. Space heating conversions would be economic, unless constrained by the specific characteristics of the dwelling.

Some sensitivity cases suggest that the fuel savings using gas could be greater than indicated by the base case results. Higher marginal energy costs of electricity (which would result, for example, if the Columbia River downstream benefits are not used to meet B.C. requirements) would increase the fuel savings using gas. Also, consideration of environmental impacts in all jurisdictions would also increase the estimated fuel savings using gas. This is because of the impact that electricity consumption in B.C. has on electricity production in California and other out-of-province jurisdictions.

On the other hand other factors could reduce the estimated present value savings using gas. Foremost among these is a higher discount rate.

6.0 PRIVATE VS. SOCIAL PERSPECTIVE

The cost comparisons in the previous section indicate what is the preferred fuel or conversion strategy from a social or overall provincial perspective. However, the fuel choices and conversion investments that consumers make will depend on the fuel prices they pay and the costs of capital (and, therefore, discount rate) they face. Differences between (i) fuel prices and social costs, and (ii) private and social discount rates, can lead to different individual decisions from what might be identified as most beneficial from a social perspective. These differences are discussed below.

6.1 Prices vs. Social Costs

Currently, residential electricity prices include a customer charge, a 6.81¢/kwh charge for the first 550 kwh per billing period and a 4.74¢/kwh charge for all consumption over 550 kwh. The marginal price of electricity, i.e. the price that would bear on changes in consumption due to a shift to gas is the 4.74¢/kwh charge.

Electricity rates are under review and it is possible that this marginal price will be changed to reflect Hydro's long run incremental cost of electricity. However, this will depend on the outcome of a current BCUC hearing.

Natural gas residential rates include a customer service charge plus $4.21/GJ of gas consumption. The marginal price is the $4.21/GJ energy charge.

While both the electricity and gas rates can be expected to change, a comparison of the current marginal prices with the social costs estimated in the previous sections illustrates the difference between price "signals" and social costs. These differences are shown in Table 26.

TABLE 26

Prices vs. Social Costs

	GAS		ELECTRICITY	
	Estimated Social Cost ($/GJ)	**Current Marginal Price ($/GJ)**	**Estimated Social Cost (¢/kwh)**	**Current Marginal Price (¢/kwh)**
Water Heating	4.47	4.21	3.6¢ rising to 6.6¢	4.74
Space Heating	6.79	4.21	5.2¢ rising to 8.7¢	4.74

The estimated social cost of gas for both water and space heating exceeds the current marginal price. In large part this is due to the fact that gas prices do not include or reflect the estimated environmental costs. Residential gas prices also do not reflect the difference in costs between high and low load factor applications, and that is responsible for the marked divergence between costs and prices for space heating loads.

With respect to electricity, the estimated social costs for water heating loads are currently below the marginal price. This is due to the currently very low short run marginal cost of electricity supply, particularly for a high load factor application like water heating. The currently low marginal costs of electricity supply for water heating more than offsets the inclusion of environmental costs in the social cost estimate. Over the longer term the social costs of electricity will rise above current marginal prices, in large part because of the rising marginal cost of electricity supply.

The estimated social cost of electricity for space heating loads is above the current marginal price. Space heating's low load factor raises its cost per delivered kwh, but, like gas, this is not reflected in the marginal price.

Because of the differences between prices and costs, the estimated present value savings using gas will be different when calculated on the basis of prices as opposed to estimated social costs. This is shown in Table 27.

TABLE 27

Present Value Savings Using Gas

	Based on Social Cost	Based on Current Marginal Prices
Water Heating	599.90	898.50
Space Heating (Conventional Furnace)	2,920.81	2,426.71

For water heating, the savings using gas are much larger when based on current marginal prices than estimated social costs. Current prices exaggerate the advantage of gas primarily because they overstate the social cost of using electricity for water heating. They suggest that conversions to gas are more attractive than the social cost estimates would indicate.

For space heating, the savings using gas are smaller when based on current marginal prices than estimated social costs. Current prices underestimate social costs for both energy sources. Over the longer term, the net effect is to underestimate the social costs of electricity even more than gas, thereby understating the cost advantage of gas. The current prices reduce the incentive to convert to gas, though the incentive - the fuel cost saving - is still very large.

6.2 Discount Rate

In estimating the present value social cost savings using gas, a real discount rate of 8% was used. This is a rate commonly recommended in benefit-cost analyses to reflect the social opportunity cost of capital. It is the rate B.C. Hydro currently uses for its planning and project evaluations.

From a private perspective, the discount rate that will be used in any evaluation will reflect the cost of capital facing the individual, or the number of years over which the individual will benefit from the savings. It is often suggested that the discount rate individuals explicitly or implicitly apply is much greater than 8% real. Household borrowing costs alone could suggest a real discount rate in excess of 10%. The inability to borrow could result in effective discount rates in excess of 30%.

In section 5.3.3, it was shown how a higher discount rate reduces the present value cost advantage of using gas. If one were to assume a much higher private discount rate the perceived present value savings would fall further. For example, at 20% the present value savings using gas for hot water heating would fall from approximately $600 to $400. The present value savings for space heating (in a conventional furnace) would fall from some $2,900 to less than $1,000. An even higher rate would reduce the savings still further. This clearly would reduce the incentive to convert. In some cases, for space heating, [illegible]ld even reduce the incentive to use gas in a new dwelling if there was a sufficient capital cost advantage in electricity heating equipment.

6.3 Summary

There are significant differences between the estimated social cost of gas and electricity and the prices paid for them. Current prices tend to overstate the social cost savings using gas in water heating applications and understate them in space heating applications.

There may also be significant differences between the discount rate or cost of capital facing individuals and the cost of capital from a social perspective. Higher private rates can markedly reduce the perceived present value savings using gas, particularly for space heating with its relatively long appliance life.

APPENDIX A

The Effect of Resource Depletion on Natural Gas Prices[1]

This appendix addresses the assumption that underlies most natural gas price forecasts - that depletion of the resource base will force a continuing escalation of supply price once the current "bubble" is removed. It is first pointed out that the stock of marketable (or developed) reserves is replenished not only by the conventional process of exploration and development drilling but also by increases in recovery fractions from conventional reservoirs and recovery from sources not previously accessible such as tight sands. These latter sources appear especially susceptible to technological advance.

The inevitability of predictions of increasing reserves costs when forecasts are based on convention technology and geological assessment of ultimate reserves is illustrated. In contrast, studies that admit additions from any source may show upward or downward trends or no trend at all in the replacement cost of developed reserves, as is also illustrated.

A method is outlined for establishing the supply price of undeveloped reserves, a measure of pressure being placed on the resource base. In two applications this measure fails to reveal a systematic upward trend, although the results must be qualified by data limitations. It should be noted that even if the value of undeveloped reserves is not rising, higher development costs could push up the cost of marketable reserves. Evidence on trends in development cost is inconclusive and is not dealt with here.

The conclusion drawn is that while scarcity, manifest in increasing prices, will eventually occur, forecasts of significant price increases within, say, a five to ten year horizon must be viewed with scepticism. Put differently, this is to suggest that it is probably unwise to single out natural gas from other currently used basic energy sources as being more likely to feel the pressure of imminent resource scarcity.

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[1] Prepared by Professor Paul Bradley, Department of Economics, U.B.C.

Forecasts of the prices of petroleum and minerals are almost always presented in the context of, How fast will price rise? This relates, no doubt, to the "common sense" notions that finite resource endowments must eventually be exhausted and that the using-up process involves moving to successively lower grade - hence, more costly - stocks. This common sense is buttressed by the preoccupation that academic resource economists have displayed with models of optimal rates of use that rest on the assumption of either a fixed resource stock or a resource stock comprising increments that diminish in quality in a specified fashion. Although the various means by which technology can offset this physical depletion are acknowledged, because there is no convincing model to specify how technology will unfold its effects are typically relegated to the qualification that depletion forecasts are conservative.

In fact, forecasts of supply-induced escalating petroleum prices have typically been falsified by events. This appendix addresses the question of whether resource depletion is likely to drive up natural gas prices in the five to ten year "medium" term. It proceeds by first noting the sources of new reserves and the potential they afford for gains through advancing technology. It then indicates the bias in price forecasts derived from resource base estimates, making reference to National Energy Board forecasting procedures. This approach is compared with a reserves replacement cost approach, illustrated by a recent study carried out at the Canadian Energy Research Institute. Subsequent paragraphs sketch a procedure by which market information can be employed to value undeveloped reserves, a measure of the pressure being placed on the resource base. While data have not been available to permit this procedure to be fully exploited, tentative results fail to indicate an increasing value for undeveloped reserves. The concluding paragraphs suggest that on the evidence, there is no basis for predicting that there will be significant supply induced escalation of natural gas prices in the medium term.

Before going ahead as described, it should be pointed out that barring an unforeseen return to federal policy of the 1970s, the Canadian market for natural gas cannot be separated from that in the United States - the market is continental and delineated by the pipeline network. The implication of this is that natural gas prices in Canada will be determined by the continental demand-supply balance. It is beyond the scope of this section to examine the possible evolution of this balance - rather the proposition here is that because of their fundamental deficiencies, petroleum supply forecasts have exaggerated impending scarcity. This is demonstrably the case with crude oil, and is likely to be the case again with natural gas, even viewed in the continental, rather than strictly Canadian, context.

Three sources of oil and gas reserves additions are commonly recognized (see, e.g., Woods,1986). They are: (1) the discovery of new fields; (2) reserves additions to known fields using current practice and technology; and (3) incremental recovery of the resource-in-place in known fields beyond that expected from current practice and technology. As will be discussed below, most supply-based forecasts are focused on the first two categories. Thus improvements in technology can affect supply chiefly by bringing identified but lower quality resource stocks within economic reach. The impact of improved technology could still be significant, but, in fact, it is the third, often neglected category, where technology can yield major additions to reserves.

U.S. experience has demonstrated the importance of this third source of new reserves. As of 1986 it was estimated that since the mid-1970s "the reserve additions due to improved recovery have accounted for more than two-thirds of lower-48 oil reserve additions" [Woods,1986]. There has been a tendency to relate improved recovery to advanced EOR (enhanced oil recovery techniques). However, much of the increase is attributable to the fact that it now appears that oil in reservoirs is not as mobile as previously thought. Substantial increases in reserves continue to be reaped by more intensive infill drilling with only limited use of EOR.

Turning to natural gas, reserves additions through category 1, new discoveries, or the development of known, but previously ignored reservoirs has been dominant, and conventional wisdom has suggested there was limited potential for improved recovery because primary recovery of gas-in-place in nonassociated pools was thought to be in the neighbourhood of 80 to 90 percent. Opinion on this matter is changing: recent infill drilling in the giant Hugoton field indicates that earlier reserves estimates actually represented a recovery factor of about 55 percent [Woods, 1986, quoting the **Oil and Gas Journal**]. This, supported by evidence elsewhere, makes it appear that improved recovery of gas-in-place will be a significant source of new reserves. Recovery from tight formations (tight sands and Devonian shale) will require advanced technologies to be economic, but the potential from this source is known to be very large.

To summarize: reserves additions for natural gas, as for crude oil, come from a number of sources. New discoveries and conventional appreciation with development drilling have been dominant, but may not continue to be in the future. The potential significance of improved recovery is more difficult to assess because it is more contingent upon improved technology. It does seem likely, however, that most supply forecasts and evaluations of current drilling performance seriously understate the future availability of reserves through neglect of category 3 additions. To illustrate, a recent Canadian study will be briefly described.

Long term forecasts based on geological assessments extrapolate the frequency and size of finds in well explored areas to less explored areas that are judged to be similar. An good example is provided by work carried out at the National Energy Board (NEB). In the interval from the adoption of its "Market Based Procedure" in July 1987 until March 1990 the NEB required applicants for an export license to provide a benefit-cost analysis that would demonstrate that revenue received would cover all Canadian costs. Recognized costs included user cost, which the Board defined as "the increased cost of satisfying future gas demand from more costly reserves which results from the more rapid depletion of existing reserves associated with an incremental export" [NEB, 1989]. The existence of user cost presupposes knowledge of future reserves stocks. This can be pictured - and it was in the NEB framework - as a sequence of blocks of reserves arranged in order of ascending cost.

The NEB benefit-cost methodology rested on analysis of the type described by Bowers and Kutney [in NEB, 1989; also Bowers and Kutney, 1989]. The analysis began with estimates of undiscovered resources provided by the Geological Survey of Canada (GSC). These estimates are, of course, uncertain, and take the form of statements like the following: "...at the 95 percent probability level, the GSC estimates that...4834 billion m^3 of marketable natural gas are technically recoverable from western Canada by conventional production practices. At the 5 percent level the corresponding estimate (is)...5794 billion m^3 of marketable natural gas." The next step is to project the cost structure by which these reserves can be attained.

The costs of reserves additions recognized by Bowers and Kutney include "those costs which could be a function of development of the resource base, namely costs for exploratory and development drilling, geological and geophysical assessment, field equipment and production." To relate these expenditures to the unit cost of reserves additions, various cost determining parameters must be extrapolated from historical trends. Key among these are reserves added per production well (taking into account both exploration and development wells), drilling success ratios, and average well depths.

Reserves per meter drilled in exploration are assumed to decline because it is assumed that larger reservoirs are discovered first. Hence a curve showing cumulative reserves as a function of cumulative exploratory drilling approaches the estimated volume of ultimate reserves asymptotically; that is, incremental reserves per meter drilled decline toward an ultimate value of zero. Since exploratory drilling success ratios have not displayed a marked trend, Bowers and Kutney assumed them to be constant at the historical average. Combining these two extrapolations results in incremental figures for reserves found per successful exploratory well. Taking account of reserves added by development drilling (the details of the procedure need not be recounted here), the authors arrive at corresponding figures for reserves added per production well, summarizing the results of all drilling. Reserves added per production well show a systematic decline as the stock of undiscovered reserves is exploited because of the initial diminishing returns assumption. Given the further assumption that drilling costs per well increase, though only at a slow rate reflecting increased depth, it must follow that the unit cost of incremental reserves is systematically increasing.

The NEB model of reserves supply thus consists of an upward sloping curve, in practice described stepwise, which accounts for total ultimate reserves forecast on the basis of geological evidence. Systematic increase in production cost is built in, as described above. The methodology also implies the existence of a user cost component, as defined by the NEB. This represents the increase in present value cost of meeting future demand resulting from an incremental increase in current output.

The significance of the analysis is that rising production cost is built in. This implies price must rise to cover this cost. The supply described is explicitly that recoverable "by conventional production practices," therefore not recognizing category 3 possibilities as defined above. The Bowers and Kutney analysis is also limited to western Canada, though the NEB would acknowledge that there are other Canadian sources of natural gas. Nevertheless, the NEB methodology and the supporting analysis exemplify the downward bias that typifies supply estimates, and results in forecasts of imminent and systematic price increases.

A second example of supply analysis is provided by a recent study from the Canadian Energy Research Institute (CERI) [McLachlan, 1991]. This study purports to report replacement costs for natural gas in western Canada. Its methodology is straightforward - basically, annual exploration and development expenditures are divided by reserves additions to yield a dollar per m^3 figure. Long-term replacement cost is calculated using several refinements. Reserves are not those initially credited to a discovery, rather an estimate of fully appreciated reserves based on historical experience of the results of development drilling. Geological and geophysical expenditures are lagged one year from the datum year and land acquisition costs (which as rents should not be included in the analysis) are lagged two years. Development expenditures, in contrast, enter the replacement cost calculation through a leading structure that need not be detailed.

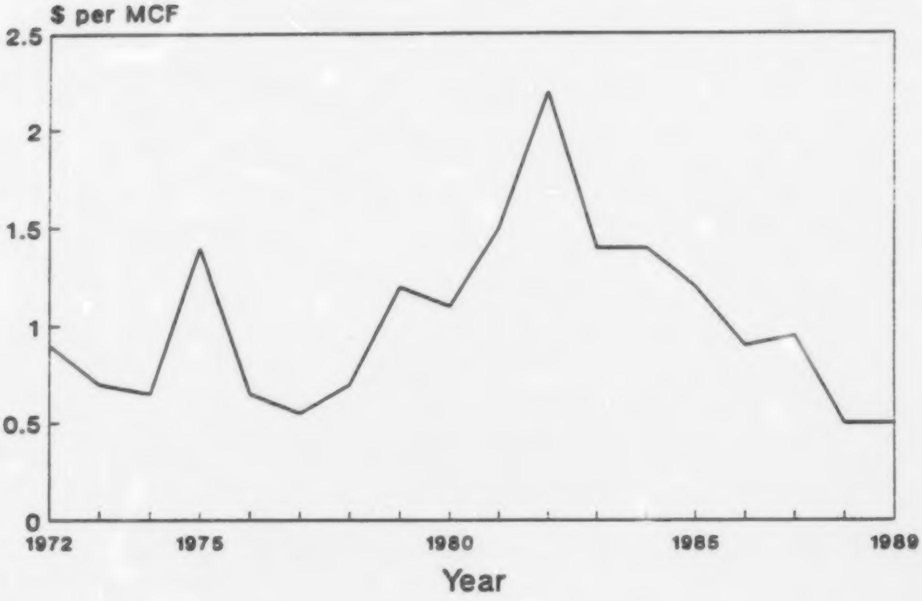
The McLachlan analysis is not bounded by the geological assumptions underlying the one described above. Thus actual reserves additions, regardless of their source, are recognized. The appreciation factor, however, is still based on past experience. With this qualification, the intent of the analysis is to track actual replacement cost experience. Over the period considered, from 1972 to 1989, long term natural gas replacement cost in Alberta (base case) displays no apparent upward or downward trend. This is shown in Figure 1.

FIGURE 1

Long Term Replacement Costs for Marketable Natural Gas

Alberta

(1989 Constant Dollars)



Interpretation of Figure 1 as the desired replacement cost estimate is muddied by departures from what would be a market equilibrium. In the earlier years prior to deregulation the replacement costs may be biased upward because in the absence of market opportunity discoveries were probably not fully developed. The peaking in the 1981-1984 period was caused by the frenzy of drilling that took place in the wake of the second oil price shock and prior to the subsequent price collapse; a minor version occurred following the first price shock but at that time price regulation was effective. When the drilling rate accelerates, less advantage is taken of the learning curve. Perhaps more important, factor costs are driven up, as the anticipated high returns prompt claims on the corresponding economic rents.

The McLachlan study suggests that in Alberta the systematic increase in the supply price of natural gas that derives from stock models like the one identified with the NEB is not being experienced. This is consistent with the less restrictive nature of the analysis.

To put the matter in another perspective the remainder of this appendix describes a procedure for utilizing market information rather than physical supply costs to gauge trends in natural gas prices.

Unfortunately the market for developed natural gas reserves is not well organize like, for example, the spot market for crude oil. However, information about the value of underground reserves is increasingly becoming available. Specialized firms evaluate underground petroleum reserves to aid companies in negotiating the purchase and sale of these assets. The J. S. Herold company in the United States, for example, has provided this service for many years. The market test comes when underground reserves are actually bought and sold, so isolated data points can be determined from actual transactions. The procedure to be described utilizes information on the value of developed reserves and development costs to infer whether increasing scarcity is causing systematic price increases.

Define V" as the value of developed reserves, expressed in \$ per m^3. Development investment, I, represents the expenditure required to create developed reserves given that natural gas in place has been identified. For so-called conventional reserves the bulk of this expenditure would result from development drilling, but the broader definition includes expenditure for various recovery systems. Developed reserves would not be supplied at a price that only covered development cost, because to create the reserves the seller must also have the gas in place.

The value of gas in place (undeveloped) depends on replacement opportunities. One possibility is that suggested by the McLachlan study - undeveloped reserves should be valued with reference to replacement cost. That specifies a supply-demand equilibrium price equation for developed reserves:

$$V'' = I + rc \qquad (1)$$

where rc = replacement cost. It should be noted that this definition of replacement cost is not the same as the one used by McLachlan; it represents the cost of finding new gas in place.

There is another, polar possibility, and that is that no replacement possibility exists. In this case the gas in place would be valued at user cost as defined in the paper by Hotelling [1931] and in its numerous elaborations. In its simplest version user cost represents the present value of the gas in place if sold at any future time when price would be higher because of the growing scarcity. This value implies arbitrage so that the fixed stock of resource is used at a rate that maximizes its value. In this situation the supply-demand equilibrium price equation is:

$$V'' = I + uc \qquad (2)$$

where uc = user cost.

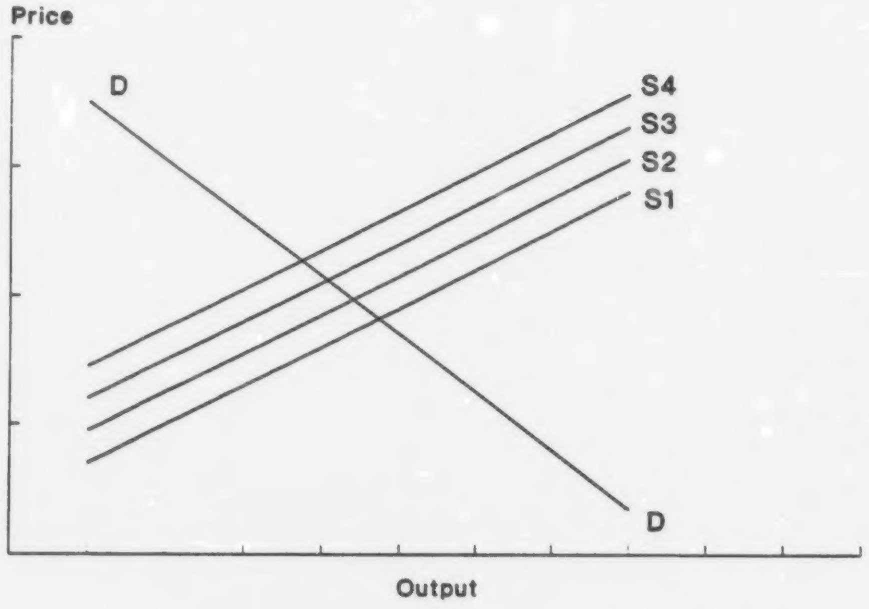
There are intermediate possibilities. If a fixed supply situation of the Bowers and Kutney type is present in addition to the increasing replacement cost there will be a user cost component, since when gas in place is used its immediate replacement cost must be taken into account as well as the fact that all future replacement costs will be higher. This, however, is a subtlety that can be ignored in combining equations 1 and 2:

$$V'' = I + \min(rc, uc) \qquad (3)$$

Figure 2 shows demand and supply curves in this market for developed reserves.

Considering only the supply side, in the pure user cost case (equation 2) the supply curves would systematically shift upward from year to year with user cost increasing according to the Hotelling intertemporal arbitrage condition. On the other hand, following the Bowers and Kutney model, replacement cost may dominate (equation 1), so that once again there is a systematic upward shifting of the supply curve, but with the progression of the shifts determined by the availability of gas in place in the successively more costly tranches. Another possibility is that no systematic trend is observed. This would be in accord with the openendedness implicit in the McLachlan procedure and the possibility suggested above that pressure on replacement cost is relieved by increasing recovery from already identified gas in place.

Figure 2
Hypothetical Market for Developed Reserves



Two empirical applications of this market oriented model will be described, each an effort to detect systematic increases in either the user cost or replacement cost of gas in place. If time series data for (V" - I) are assembled then, referring to equation 3, this should reveal trends in either replacement cost or user cost for gas in place.

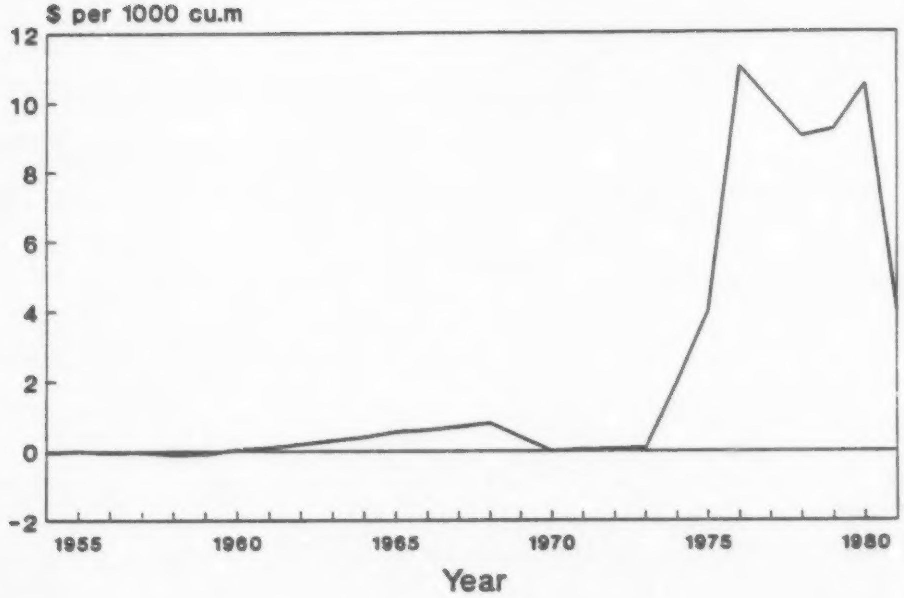
In a study carried out for the Economic Council of Canada, R. S. Uhler (1986) developed a time series of the value of developed natural gas reserves in Alberta. These values were calculated based on current net backs, that is, field gas prices less taxes and royalties. He then projected prices and production rates, permitting calculation of the present value of reserves in a reservoir. This procedure is that used by the Herold company and others; it suffers from the fact that the values have not been validated by actual market transactions. Uhler also reported a series of annual values for development expenditure per m^3 of reserves additions. These two series permit calculation of (V" - I) = min(rc,uc) as in equation 3.

The resulting graph is shown in Figure 3. The earliest values are clearly invalid and probably explained by the low value attached to natural gas when associated gas represented a significant share of new production. Over the decade from the early 1960s until 1973 there is no discernable trend in this measure of the value of new gas in place. The subsequent explosions in value correspond to the frantic activity at the time of the oil price shocks. This is the same distortion that shows in the McLachlan replacement costs figures and appears for the same reasons. The crucial additional data required show the trend over the last decade are unfortunately not available at this time. Hence, while systematic depletion - as indicated by a consist upward trend in the value of new gas in place - is not demonstrated in Figure 3, the exercise is inconclusive.

FIGURE 3

User or Replacement Cost for Alberta Natural Gas

(current dollars)



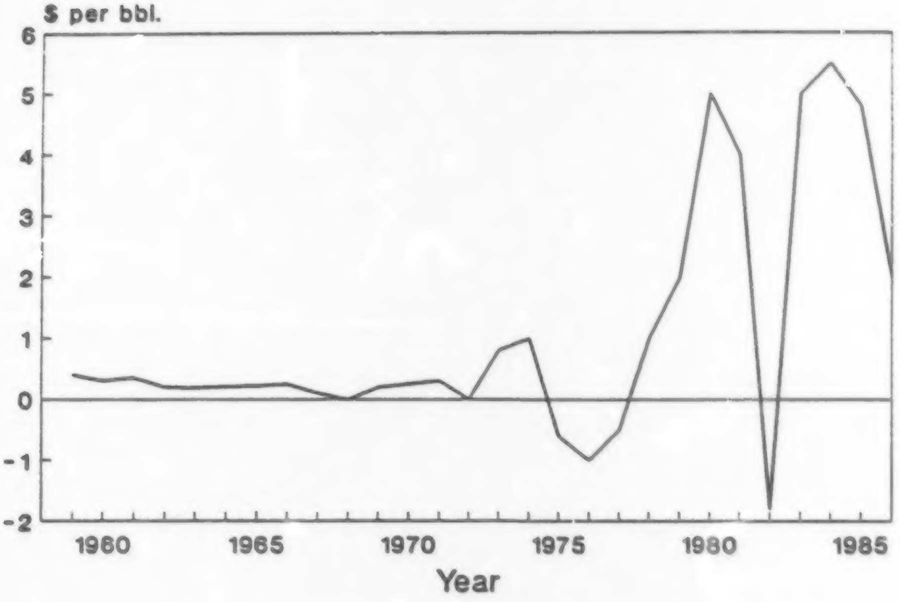
Additional evidence can be supplied by considering similar data for crude oil. Adelman, et.al. (1990) examined developed reserves values and development expenditure for crude oil in the continental United States for the period 1959 to 1986. The resulting measure of the value of new crude oil in place, (V" - I), is plotted in Figure 4. Again, the disequilibrium resulting from the oil price shocks, particularly the second, spoil the data in the later years. What is significant, however, is that no increasing trend in value is evident from 1959 until the first shock. Recalling that this value is the lesser of replacement cost or user cost, the implication is that replacement cost dominated and was not increasing. This is in part explained by the fact noted above, that the bulk of reserves additions were coming from improved recovery in known fields. Use of analogy is hazardous, but it must be pointed out that continental United States is certainly the area in the world most intensively explored for crude oil, yet output has been maintained without convincing evidence of the type of pressure on the resource base implied by analysis of the Bowers and Kutney sort.

To summarize, this appendix does not provide the basis for a forecast of natural gas supply prices as related to cumulative production - indeed, the possibility of such a forecast is questioned. Insight can be gained by examining trends, but such analysis to date has generally been incomplete and poorly formulated. One particular deficiency relates to trends in development investment per m^3 of marketable gas reserves. Resolution of this investment into categories is required; a broad division would be between conventional and unconventional, the latter being, for example, recovery from tight formations. While per unit costs in the latter category would be higher, this would be offset by the fact that no additional finding cost (replacement cost as defined by (V" -I)) is required.

FIGURE 4

User or Replacement Cost for U.S. Crude Oil

(current dollars)



The point to be made is that the notion must be highly suspect that there is a gas "bubble" and that once it is dissipated natural gas prices will begin a predictable, systematic upward trajectory. The McLachlan study, though flawed, shows no evidence of impending scarcity. The trend in a proxy measure of the value of new gas in place, though the series is incomplete, also reveals no such tendency, and this result shows up again in U.S. crude oil experience. Scarcity, manifest in increasing prices, will eventually occur, but forecasts of significant natural gas price increases within the medium term must be viewed with scepticism.

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APPENDIX B

Alternative Markets for B.C. Gas[1]

Current Sales

Table B-1 shows the sales of B.C. gas by market region for the contract year November 1989 to October 1990. During that year, B.C. gas sales totalled 444 PJ. Sales to domestic markets were 248.6 PJ or 56% of total sales. Other Canadian sales totalled 27.7 PJ or 6% of total sales. Most of these sales were in the Ontario/Quebec markets (20 PJ or 4.5%). U.S. sales totalled 168.7 PJ or 38% of total sales. The Pacific Northwest is the major U.S. market area. Sales to this market were 141.7 PJ or 73% of ex-B.C. sales in the 1989/90 contract year.

Also, shown in Table B-1 is the split between firm and interruptible contracts. Sales in the B.C. market are mainly under firm contracts of one year or more. Sales to other Canadian markets are mainly on an interruptible best efforts basis, 30 days or day-to-day. Sales to the U.S. market were split evenly between firm and interruptible. On the whole, about two-thirds of B.C. gas was sold on a firm contractual basis in the 1989/90 contract year.

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[1] Prepared with the assistance of Brent Friedenberg Associates.

TABLE B-1

Sales of B.C. Gas by Market Area

(Contract Year: November 1989 to October 1990)

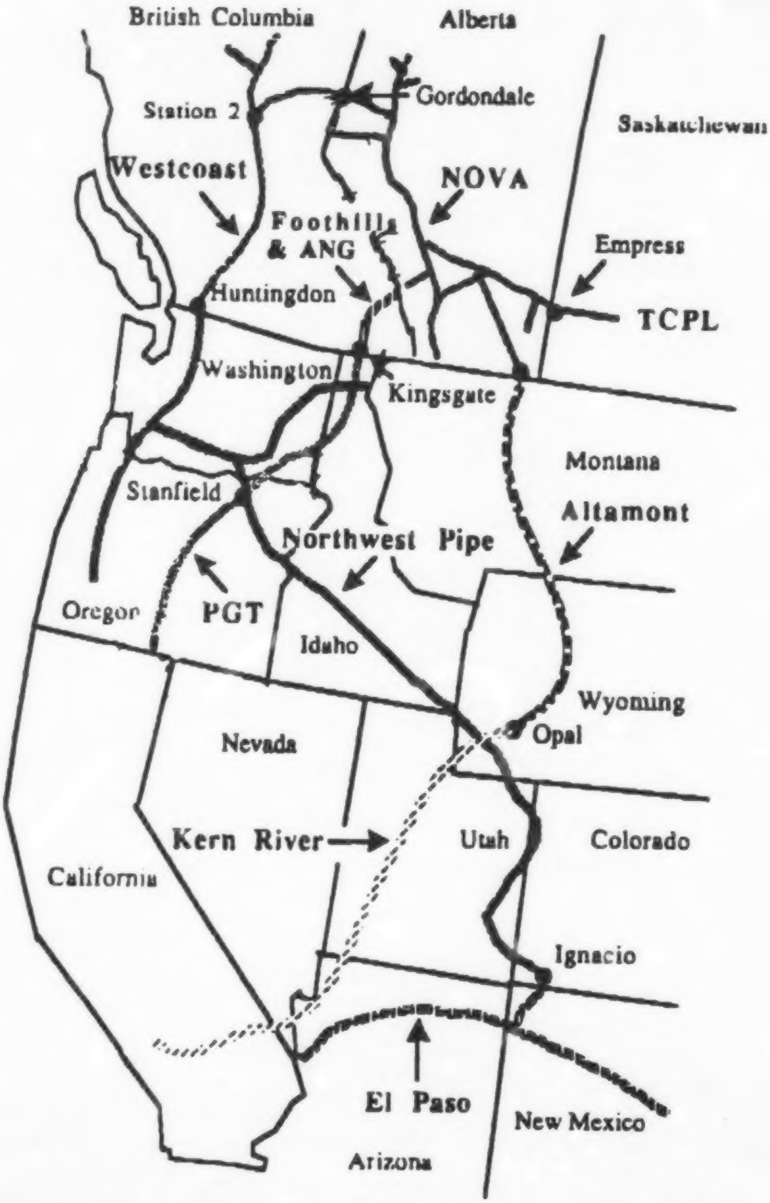
	PJ	%	Firm/-Interruptible
B.C. Domestic Sales	248.6	56.0	75/25
Other Canadian Sales			
Alberta	6.7	1.5	
Ontario/Quebec	20.0	4.5	
Total Other Canadian	26.7	6.0	25/75
U.S. Sales			
Pacific Northwest	141.7	31.9	
California	10.1	2.3	
Rocky Mountain	11.8	2.7	
U.S. Midwest & North	5.1	1.1	
Total U.S. Sales	168.7	38.0	50/50
TOTAL	**444.0**	**100.0**	**63/37**

Source: British Columbia Ministry of Energy, Mines and Petroleum Resources, **Natural Gas Market Update**, February, 1991.

Pipeline Interconnections

Figures 1 shows the pipeline interconnections for delivering B.C. gas to markets outside of the province. Also, shown on this figures are the proposed pipeline expansions for delivering more Canadian gas to the California market.

Figure 1
Pipeline Interconnections for B.C. Gas


British Columbia
Alberta
Station 2
Gordondale
Saskatchewan
Westcoast
NOVA
Foothills & ANG
Empress
Huntingdon
TCPL
Washington
Kingsgate
Montana
Stanfield
Altamont
Northwest Pipe
PGT
Oregon
Idaho
Wyoming
Opal
Nevada
Kern River
Utah
Colorado
California
Ignacio
El Paso
New Mexico
Arizona

The majority of B.C. gas is transported on the Westcoast Energy pipeline system.[1] Westcoast transports gas to the B.C. LDC's and to border export points. The capacity on Westcoast's mainline south of Station 2 is approximately 1500 mmcfd. The gas is transported to B.C. customers in the southern portion of the province and export customers at Huntingdon. The export capacity at Huntingdon is 782 mmcfd. The only other export point on the Westcoast system is on the B.C./Alberta border where Westcoast connects with the Alberta NOVA system. The export capacity here is 190 mmcfd.

At Huntingdon, the Westcoast system interconnects with the U.S. Northwest Pipeline (NWP) system. This system transports gas to markets in the U.S. Northwest, the main markets being in Washington and Oregon. The gas transported on the NWP system is sourced from Canada, primarily British Columbia, and the U.S. Rocky Mountain region (Wyoming and New Mexico). The physical configuration of the NWP system is such that around 58% of its gas supply must be sourced from Canada and 42% from the U.S.[2]

NWP interconnects with the Pacific Gas Transmission (PGT) system in northern Idaho and near Stanfield, Oregon. NWP has capacity to accept 362 mmcfd of Canadian gas off of the PGT system. Some of this gas is sold in the Northwest, but most, some 240 mmcfd, is taken off of the PGT system at Stanfield and transported to Southern California via NWP's interconnection with El Paso at Ignacio.

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[1] There are B.C. gas fields, along the broader with Alberta, that are not connected to the Westcoast system but rather are directly connected to Alberta's NOVA system. The major one is the Elmworth gas field which extends from B.C. into Alberta. The netback value of B.C. gas which is directly connected to the NOVA system is not particularly relevant in determining the opportunity of gas sold within B.C. since B.C. customers do not have access to this gas.

[2] The NWP system is narrow in the middle of its system and wider at its north and south ends. This restricts the amount of U.S. gas it can deliver into the Northwest market.

NWP is planning a number of expansions that will increase B.C.'s ability to export into the Pacific Northwest and California markets. A 253 mmcfd expansion is planned at Huntingdon, increasing NWP's receipt capacity to over 1000 mmcfd. Planned interconnections and capacity expansions with PGT, Kern River and El Paso will allow 232 mmcfd of B.C. gas to reach the California market on a firm basis from the Huntingdon export point.[1]

There are also plans to expand the Westcoast/NOVA interconnection on the B.C./Alberta border. Alberta & Southern (A & S) currently holds 100 mmcfd of capacity at this removal point and has requested an additional 200 mmcfd to be in place by November 1993.

With the proposed expansions on NWP and the Westcoast/NOVA interconnection, the capacity for delivering B.C. gas to California could approach 530 mmcfd by 1993/94. This compares to the present capacity of approximately 800 mmcfd for delivering B.C. gas into the U.S. Northwest via the Huntingdon export point.

Alternative Markets for B.C. Gas

The increased capacity to deliver gas to California will open up a major new market area for B.C. gas. The increased capacity at the Westcoast/NOVA interconnection on the Alberta border will also expand B.C.'s ability to sell gas in Alberta or eastern markets via NOVA and the TCPL or Foothills (east leg) systems. Thus, one can expect a more diverse distribution of B.C. exports in the future than what currently occurs.

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[1] The B.C. gas currently reaching California via Huntingdon are largely interruptible volumes.

Despite the new opportunities, the netbacks from these market areas are not likely to be higher than from the firm sales to the Pacific Northwest.

In Table B-2, current prices, transportation costs and estimated netbacks from California and eastern markets are shown. Except for the long term firm sales to eastern Canadian LDC's, the estimated netbacks are quite low. Prices could rise above current levels, but they would have to rise substantially to reach the netbacks currently offered by firm sales to the Pacific Northwest.

TABLE B-2

Current Netbacks from Alternative Markets

(Cdn. $/GJ)

	California via Huntingdon	**California vis Kingsgate**	**Eastern LDC's Long Term Firm**
Current Price	2.21	2.21	1.90*
Transportation and Processing			
- Westcoast	(.61)	(.47)	(.47)
- Other	(.88)**	(.97)**	(.16)
Netback	.72	.77	1.27

* At Empress

** Includes estimated NWP and PGT costs after proposed expansions.

California sale netbacks at Kingsgate are currently much higher than suggested by Table B-2. The Pacific Gas Transmission tariff is only approximately $.17/GJ, which contributes to the high netbacks for A & S producters selling to Pacific Gas and Electric in northern California. The cost of transporting gas on the expanded PGT system will be considerably higher, as reflected in the table. The new capacity will not only entail higher transportation costs, but will also depress or at least restrain market prices.

B.C. gas exports will continue to be concentrated in the Pacific Northwest, where B.C. gas is most competitive and likely to realize the highest netbacks. The best alternative to firm sales in the Pacific Northwest are sales to eastern Canadian LDC's. With LDC's in Ontario and Quebec contracting outside the WGML pool, this market could be important in maintaining the price of B.C. gas in domestic and U.S. northwest markets.

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SUPPLEMENT

Fuel Choice in Space and Water Heating Applications in British Columbia

FUEL CHOICE IN SPACE AND WATER HEATING APPLICATIONS IN BRITISH COLUMBIA

1.0 INTRODUCTION

Different fuels or energy sources for space and water heating applications give rise to quite different economic and environmental costs. From a policy perspective, these differences raise two fundamental questions.

- what are the economic and environmental costs associated with the different fuels; and
- are these costs fully or accurately reflected in the market prices facing individual consumers.

The costs associated with the different fuels are key factors governing which fuels are most efficient or socially desirable in different applications and contexts. The extent to which costs are properly reflected in prices bears on the likelihood of the preferred fuels being selected in private market decisions, and the corresponding need or rationale for government and utility programs to promote more efficient fuel choices.

The purpose of this report is to discuss the components of the economic and environmental costs of different fuels in different applications and contexts, and to identify factors that can contribute to a divergence between these costs and the market prices facing individual consumers. No attempt is made to quantify the costs or any differences between costs and prices. However, approaches for the quantification of different cost components and cost-price relationships are identified and discussed.

2.0 COST COMPONENTS

Space and water heating requirements can be met by a number of different energy sources. For purposes of this report, the three principal alternatives are considered: electricity, natural gas and fuel oil. Natural gas is the dominant fuel used for space heating where gas service is available; electricity is the dominant energy source, particularly in new housing, where there is no gas service. Electricity is also the principal energy source for water heating in most areas, though programs have been initiated to encourage a shift from electric to gas water heating. The use of fuel oil in either application is falling and limited almost exclusively to areas where gas service is not available.

For all of these energy sources, there are economic and environmental costs in the production, transmission and distribution of the fuel requirements, and in the acquisition, installation and use of the space or water heating equipment. The nature of these costs is described below.

2.1 Fuel Cost Components

Production:- In Table 1, the nature of the costs to produce the fuel or energy required for space and water heating is outlined. In all cases, the costs depend on the source of the incremental fuel requirements and, in this respect, a distinction is made between the short and long run. In the short run, the fuel will be supplied from existing sources or capacity; in the long run new sources or capacity will have to be developed to meet the requirements for space or water heating.

TABLE 1

Fuel Production Cost Components

	Electricity	**Natural Gas**	**Light Fuel Oil**
A. Short Run			
Source of Incremental Supply	Increased thermal production; increased imports; or reduced exports	Increased production and processing of existing B.C. reserves	Increased import of crude oil for local refining
Major Economic Cost Components	Increased expenditures for gas and operation of Burrard; increased expenditures for imports; and/or reduced revenues from exports	Extraction and gas processing costs User cost associated with the depletion of non-renewable resource base	Expenditures on purchase and transport of crude oil Expenditures for increased refining operations
Major Environmental Cost Components	Increased air pollution from thermal power production as well as impacts associated with the production of the fossil fuels	Increased air pollution from gas processing	Risks associated with transport of crude Increased air pollution from increased refining
B. Long Term			
Source of Incremental Supply	Increased hydro production	Increased production and processing of new B.C. or other reserves	Increased import of crude oil for local refining or increased import of refined product
Major Economic Cost Components	Development costs for new capacity	Exploration and development costs Extraction and gas processing costs User cost associated with the depletion of non-renewable resource base	Expenditures on purchase and transport of crude oil Expenditures for refining (or import of refined product)
Major Environmental Cost Components	Resource losses associated with dam development and flooding	Land use impacts associated with gas exploration and development Air pollution from gas processing	Risks associated with transport of crude Air pollution from increased refining

Given the nature of B.C. Hydro's system and operations, additional electricity requirements in the short run can be met by increased gas-fired thermal power production in the Burrard plant, increased imports from gas and coal-fired plants in Alberta, or reduced (thermal power-displacing) exports to the U.S. (primarily California). The economic costs associated with these sources are the increased gas and operating costs for Burrard, the increased expenditures for imports and/or the foregone revenues resulting from any reduction in exports. The environmental costs derive primarily from the air emissions associated with the increased thermal power production in B.C. or other jurisdictions.

In the long term, additional requirements will advance the need for new generating capacity. In B.C. that is most likely to mean hydro capacity. The economic and environmental costs here relate to the expenditures and impacts associated with new dam developments.

Incremental gas requirements will be met from the extraction and processing of existing gas reserves in the short run, and new gas reserves over the long term. The economic cost components include not only the extraction, processing and (in the long term) exploration and development costs, but also the user cost associated with the depletion of non-renewable gas reserves. User cost refers to the future net benefits that are foregone as a result of the depletion or use of current gas reserves. It is, in effect, a charge for the diminution of the capital that our finite gas resources represent.

The environmental costs associated with natural gas production derive primarily from the air pollution associated with gas processing and also, over the long term, from the resource losses and adverse land use impacts associated with gas exploration and development activity.

For oil, incremental fuel oil requires additional imports of crude oil, transmission to B.C. and processing in B.C. refineries. Over the long term, with the possible development of a products pipeline from Alberta, the incremental requirements could be met by imports of refined product from outside B.C. (e.g. Alberta refineries). The economic cost components include expenditures for the purchase and transport of crude oil and for the refining operations (or for product imports). The environmental costs in B.C. include the risks and impacts associated with oil transport (which are quite limited for pipeline deliveries) and the air pollution impacts associated with refining.

Transmission and Distribution:- The transmission and distribution of the fuels also generate costs in the short and long run, as summarized in Table 2.

The cost components for the transmission and distribution of electricity and gas are quite parallel. In the short run, they are confined to fuel and losses and, in cases where there is no existing service, the extension of distribution and service lines. In the long run, incremental requirements, particularly for heating requirements in peak demand periods, can be expected to contribute to the need for additional capacity, giving rise to additional construction expense. Environmental costs relate primarily to the construction of new transmission capacity, with the land alienation, wildlife and right-of-way maintenance impacts that entails.

The costs components for the distribution of locally refined fuel oil in the short and long run are the same: increased transport and bulk storage costs. Depending on the location of customers that can entail marine (barge) as well as truck transport.

TABLE 2

Transmission and Distribution Cost Components

	Electricity	**Natural Gas**	**Light Fuel Oil**
A. Short Run			
Major Economic Cost Components	Losses	Fuel and losses Service extension, construction, where required	Transport and bulk storage
Major Environment Cost Components	Possible electromagnetic radiation, though incremental effect limited	Limited	Transport risks Air pollution from truck transport
B. Long Term			
Major Economic Cost Components	Losses Construction of additional capacity	Fuel and losses Construction of additional capacity	Transport and bulk storage
Major Environmental Cost Components	Possible electromagnetic radiation, though incremental effect limited unless new right of ways are developed Land use and wildlife impacts associated with additional capacity	Land use and wildlife impacts associated with additional capacity	Transport risks Air pollution from truck transport

2.2 Equipment/End Use Cost Components

In Table 3, the nature of the economic and environmental costs associated with the acquisition, installation and use of space or water heating equipment is outlined. No distinction is made here between short and long run effects. However, one can distinguish numerous cases depending on the context in which the fuel choice is being made: new housing; replacement; advanced replacement or conversion. Not all the costs in the table would necessarily apply, depending on the context of the space or water heating application.

TABLE 3

Equipment/End Use Cost Components

	Electricity	Natural Gas	Light Fuel Oil
Major Economic Costs	Heating equipment Wiring/other installation	Meter/gas line installation Heating equipment (including vents) Losses	Storage tank Heating equipment Losses
Major Environmental Costs	Limited	Air Pollution	Air Pollution

The major economic costs for all of the fuels are the capital and operating costs of the heating and related equipment plus, in the case of gas and oil, the efficiency losses. The major environmental costs are related to air emissions in the combustion of natural gas or fuel oil.

2.3 Summary

In Table 4, the major long run cost components associated with the different fuels are summarized.

As shown in the table, the cost components for light fuel oil are for the most part different in nature from electricity or natural gas. This is due in part to the fact that incremental crude oil requirements will in all likelihood be met from non-B.C. sources of supply, and also that the transmission and distribution process is so much different.

TABLE 4

Cost Component Summary - Long Run Perspective

	Electricity	**Natural Gas**	**Light Fuel Oil**
Economic Costs	Incremental hydro electric generation costs	Exploration, development, extraction, processing and user costs associated with incremental gas supply	Crude oil import and refining costs (or refined product import costs)
	Incremental transmission, development and maintenance costs	Incremental transmission development costs	Product transportation and bulk storage
	End use equipment and installation costs	End use equipment and installation costs	End use equipment and installation costs
	Transmission and distribution losses	Transmission distribution and end use fuel and losses	Refining and end use fuel and losses
Environmental Costs	Resource losses and land use impacts associated with hydro development and new transmission development and maintenance	Resource losses and land use impacts associated with gas exploration and development and new transmission development	Crude oil and refined product transport risks
	Possible electromagnetic radiation associated with transmission	Air emissions from gas processing and end use	Air emissions from refining, transport and end use

The cost components for electricity and natural gas have more common elements, because of similar transmission and distribution modes. However, there are major differences. The nature of the production costs are very different, and a key question in evaluating the relative advantage of the two sources is how the incremental costs of hydro development compare to the incremental costs of gas supply over the long term.

Transmission development, end use equipment and fuel and loss cost components are similar in nature, but of course their magnitude can differ greatly. The extent of such differences is also important in evaluating the relative advantage of the two sources.

Finally, the nature of the environmental costs are very different – for electricity dominated by the resource losses associated with incremental hydro development; for gas dominated by air emissions in gas processing and end use. The nature and significance of these differences is also a key factor in evaluating the relative advantages between the two sources.

3.0 MEASUREMENT ISSUES AND METHODS

The actual comparison of costs among the different fuels requires identification of the incremental requirements and their associated costs. For a number of the cost components, this measurement exercise is relatively straightforward. Price, efficiency and other data exist that can be used to develop estimates of incremental costs.

However, for at least three major components, the measurement or estimation of cost poses considerable challenge:

- the incremental cost of hydro supply;
- the incremental cost of new gas supply; and
- the costs or significance of the environmental effects.

Methods and issues that should be considered for each of these are outlined below.

3.1 Incremental Cost of Hydro-Electric Supply

Incremental cost refers to the increase in costs of supply caused by a given increase in demand. For electricity, the effect of an increase in demand, over the long term, is to advance the timing of the need for additional generating capacity -- in B.C. Hydro's case, hydro-electric capacity. This advances capital expenditures and, therefore, increases the present value of the total expenditures that will be incurred by B.C. Hydro to meet its requirements. The amount by which the present value of B.C. Hydro's total expenditures increases as a result of a given increase in demand is the incremental long run cost of supply.

In order to estimate incremental costs, it is necessary to simulate the operation and expansion of the B.C. Hydro system under a base and "incremental" demand scenario. The annual operating and capital expenditures under the two scenarios can then be used to determine the annual and present value increase in costs associated with the increase in demand.

The magnitude of the incremental costs, determined in this way, will depend on a number of key factors. The "base case" scenario in itself can affect the magnitude of the incremental costs, because it determines the mix and timing of projects affected by an increase in demand. This suggests careful consideration of the likely impact of DSM, possible sources of new export as well as domestic demand, and other factors that may affect B.C. Hydro's load forecast and "base case" expansion plan. The extent of the increment (or decrement) in demand due to a shift to (or away from) electric space and water heating can also affect the incremental costs, even on a per unit basis. The potential size of these heating markets must also be carefully considered for the analysis.

Aside from the demand scenarios, the costs of new capacity are obviously critically important. A key factor in this regard is the discount rate, or assumed cost of capital, that is used to present value the expenditures with and without any change in demand.

B.C. Hydro is currently using an 8% real discount rate for its planning purposes. That rate is commonly used for social benefit-cost analysis. However, given the importance of this factor, sensitivity analysis at lower and higher rates (e.g. 6% and 10%) should be undertaken.

3.2 Incremental Cost of New Gas Supply

The incremental cost of new gas supply includes exploration and development costs, extraction and processing costs, and user costs, i.e. the costs of depleting B.C.'s finite non-renewable gas resource base.

Exploration and development costs depend primarily on drilling costs, well depths, success ratios, and reserves per successful well. One might expect that as high potential areas are explored, and more remote, less attractive prospects pursued, these factors would contribute to rising exploration and development costs per unit of gas supply over time. However, the historical evidence is unclear. There has not been a systematic real increase in exploration and development costs in Western Canada over the past thirty years. Unanticipated resource potential and reserve additions, as well as technological improvements, have mitigated cost increases. Forecasts of future costs are difficult to make. Careful analysis of past trends is obviously required and a range of possible future scenarios should be developed.

Extraction and processing costs of proven reserves depend on a number of factors, including well depth, location, and gas characteristics. However, these are not the major components of gas supply costs over the long term, and can reasonably be estimated on the basis of current costs in the areas where new gas is likely to be found.

User cost is perhaps the most difficult component of gas supply costs to estimate. In broad terms, user cost refers to the foregone net benefits of consuming gas today instead of reserving it for some future use. It can be measured a variety of ways. The NEB developed a methodology for estimating user costs on the basis of the impact that current gas consumption has on future gas supply costs. The basic premise is that current consumption depletes existing, low cost gas reserves, forcing future consumers to higher cost gas supplies sooner than otherwise. The amount by which future gas costs rise (which depends on the estimated stock of gas that can be found and supplied at different price levels) measures the foregone net benefits or user cost of current consumption.[1] More complicated models estimate user cost on the basis of gas prices that would optimally distribute the consumption of a fixed stock of gas over time. The difference between the "optimal" prices and gas supply costs measures the user cost.[2]

Both the NEB cost impact and the optimal price models are predicated on the assumption of fixed and known (even if not discovered) geologic potential. They presume a steady depletion of the potential, and movement from low to high cost sources of supply. While seemingly reasonable, it is not clear that gas exploitation and costs have in fact moved in this way, nor is it clear how they will move in the future.

UBC Professor Paul Bradley argues that the wedge between prices and production costs may simply be the replacement cost and this replacement cost may not be rising significantly or systematically in real terms. What this suggests is that while there might be a user cost appropriate for existing supply (equal to the estimated replacement cost), the user costs for new supply over and above the expected costs of exploration and development may be minimal.[3]

The issue of user cost is central to the evaluation of the relative advantages of gas versus alternative fuel sources, and relates very much to the analysis of trends in gas exploration and development costs, discussed above. It too requires careful consideration and analysis, and a range of plausible values should be developed for purposes of any analysis of alternative fuel costs.

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[1] NEB and CERI (1989).

[2] Rowse (1985).

[3] NEB and CERI (1989).

3.3 Costs or Significance of Environmental Effects

The production, transmission and use of the different fuels all give rise to environmental impacts and costs. The principal impacts (particularly for gas and electricity) are of two general types: resource losses due to conflicting land and resource uses, and air emissions due to the combustion or processing of fossil fuels.

It is not easy to document and measure all of these effects for purposes of a fuel cost comparison. For example, there can be adverse resource impacts associated with the existence of wilderness areas and other "non-use" effects that are difficult to quantify. There can also be great uncertainty over the extent and significance of different effects. Nevertheless, steps can be taken to incorporate some of the major environmental effects in a comparative cost analysis.

With respect to land use and competing resource effects, the significance or cost of physical impacts can be assessed by the estimated value of the alternative resource activities or uses foregone or adversely affected. Alternatively, the cost of mitigating the effects (e.g. habitat replacement) can be used to measure the costs. This type of analysis is typically undertaken in major project assessment. The challenge for any cost comparison is to ensure it is done well for all of the land use effects (including, for example, gas exploration as well as major dam or transmission projects).

With respect to air emissions, two approaches can be used to quantify their cost effects: a damage cost and an abatement cost approach. With the former, the actual health, resource activity and other losses associated with air pollution are estimated. Related price effects (e.g. changes in property value) can also used to estimate damage costs. With the latter -- the abatement approach -- the costs that are incurred to reduce emissions are used to estimate the cost of increased emissions.

The abatement approach is more tractable and more widely used in the evaluation of the costs of air emissions. The analysis can be done on a pollutant by pollutant basis and be sensitive to regional differences based on the different regulatory standards in different jurisdictions and geographic contexts. Studies using this approach indicate a significant cost to the combustion of fossil fuels, particularly in polluted urban environments.[1]

To the extent some environmental effects cannot be quantified in a fuel cost comparison, they should be carefully identified. Measured cost versus non-measured environmental effect trade-offs can then be identified and taken into consideration in the overall evaluation.

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[1] See J. Duffy, Marvin Shaffer & Associates Ltd., (1990) where this approach was used to calculate the marginal environmental benefits of DSM. Sources for abatement costs were found in Chernick and Caverhill (1989).

4.0 COSTS VERSUS MARKET PRICES

From a policy perspective, the issue of fuel choice is not simply a matter of what the relative costs are. The issue or question is whether one could reasonably expect that consumers would select the most advantageous fuels in light of their relative costs. If they would, then there would be no particular need for government intervention.

Unfortunately, there are a number of reasons why consumers may not choose the optimal fuels. Firstly, they may not be fully informed of the different costs associated with the different fuels. Secondly, the fuel decision is often made by builders who do not bear the long run costs (or benefit sufficiently in the selling price) of the systems they install.

Perhaps most importantly, the prices that consumers pay may not reflect the full incremental costs of the different fuels. The decisions they make may be optimal in terms of market prices, but not full incremental social costs. There are at least three key reasons for this:

1. With respect to electricity, prices are regulated and reflect historic average costs. They do not reflect the marginal costs of electric supply. They particularly do not reflect those costs on the basis of an 8% real cost of capital, which exceed the actual (predominantly interest) costs that Hydro pays. It is possible that the residential rate is less distorted from marginal costs as compared to other rate classes.[1] However, some distortions undoubtedly remain. They can be identified by comparing the level and structure of the residential rates with marginal cost based rates as have been estimated by B.C. Hydro and its consultants.

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[1] See Sarikas and Grunau (1989).

2. The price of natural gas may not reflect the incremental cost of new gas supply as discussed in section 3.2. Ideally, royalties provide a wedge between current supply costs and the optimal prices including replacement and/or user costs. However, given the manner in which royalties are determined there is no reason to believe that this ideal relationship in effect holds. Careful study into the relationship between natural gas prices and incremental costs of new gas supply is required. This is not only critical to the evaluation of the costs of alternative fuels but also to the determination of appropriate government policy, both in terms of natural gas pricing and fuel choice.

3. Some of the environmental effects are incorporated in the prices that consumers pay. For example, the costs that Hydro incurs to mitigate and compensate for resource impacts are incorporated into Hydro's costs. However, many of the environmental effects are not fully incorporated or incorporated at all into the fuel prices. Most noticeably, there is no charge for air emissions, and the costs associated with these are not incorporated into fuel prices. Also, adverse impacts on potentially important resource values (e.g. wilderness effects and other non-use values) are not typically addressed or incorporated into energy prices. The significance of this must obviously be considered for policy analysis.

In summary, there are reasons why prices may not reflect costs and why consumers may not choose the optimal fuels. This suggests careful consideration of the relative costs of different fuels and the policy measures that should be taken to promote better fuel choice.

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